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DESIGN TRENDS AND OPERATING PROBLEMS IN COMBUSTION MODIFICATION OF INDUSTRIAL BOILERS

Battelle Columbus Laboratories

Prepared for
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16. ABSTRACT The report gives results of an air pollution emissions control study to: characterize the current field population of industrial boilers; identify trends in boiler design; and assess operating problems associated with combustion modification. Statistics supplied by the American Boiler Manufacturers Association were analyzed to describe the field population and recent sales trends for firetube and watertube industrial boilers in the range from 10 million to 500 million Btu/hr. Boiler capacity, design type, mode of direction, primary and secondary fuels, firing method (for coal), industrial classification, and geographic region of the boiler installation were all considered. When combustion modifications are used to control nitrogen oxide emissions from industrial boilers, practical operating problems may arise, namely: fireside corrosion and deposits on boiler tubes; and flame instability, including blow-off, flashback, combustion-driven oscillations, and combustion noise or roar. These problems were assessed and research needs were identified in relation to such combustion modifications as low-excess-air operation, staged combustion, and fluegas recirculation.

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(*) Each Part has its own separate detailed Table of Contents.

ABSTRACT

As a basis for R&D planning directed to the control of air-pollutant emissions, an EPA grant study was undertaken by Battelle-Columbus Laboratories (1) to characterize the current field population of industrial boilers, (2) to identify trends in boiler design, and (3) to assess operating problems associated with combustion modification.

Statistics supplied by the American Boiler Manufacturers Association were analyzed by Battelle to describe the field population and recent sales trends for firetube and watertube industrial boilers in the range from 10 million to 500 million Btu/hr. Aspects considered were boiler capacity, design type, mode of erection, primary and secondary fuels, firing method for coal, plus the industrial classification and geographic region of the boiler installation.

When combustion modifications are employed to control nitrogen oxide emissions from industrial boilers, practical operating problems may arise, namely: (1) fireside corrosion and deposits on boiler tubes and (2) flame instability--including blow-off, flashback, combustion-driven oscillations, and combustion noise or roar. These problems were assessed, and research needs were identified in relation to such combustion modifications as low-excess-air operation, staged combustion modification, and flue-gas recirculation.

ACKNOWLEDGMENT

The authors acknowledge the helpful comments of D. G. Lachapelle, EPA Project Officer, on various aspects of this study.

A special acknowledgement and thanks are due to the American Boiler Manufacturers Association for their cooperation in making available their extensive statistics on boiler sales, to the ABMA committee personnel that contributed significant information and comments, and to ABMA Assistant Executive Director, W. H. Axtman, for his in-depth suggestions during the course of the study on boiler population and trends. The authors also acknowledge comments of others representing boiler manufacturers, utilities, and research organizations that were contacted as part of the study.

Additional Battelle staff made significant contributions to the study. T. J. Thomas handled the computer programming to analyze boiler statistics, and the following staff provided valuable insight based on their experience: D. A. Ball, R. E. Barrett, R. B. Engdahl, H. R. Hazard, R. D. Giammar, and A. E. Weller.

DESIGN TRENDS AND OPERATING PROBLEMS IN COMBUSTION MODIFICATIONS OF INDUSTRIAL BOILERS

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March, 1974

Final Report
to the
U. S. ENVIRONMENTAL PROTECTION AGENCY
on
Grant No. 802402

EXECUTIVE SUMMARY

Fossil-fuel utilization in industrial boiler plants for steam generation is almost as great as in utility boiler plants for electrical generation. Thus, reduction of nitrogen oxide emissions from industrial boilers represents a significant need for air-pollution control among stationary sources.

Industrial boilers were defined for this study as steam or hot-water boilers encompassing the range of capacity from 10 to 500 million Btu/hr output (corresponding to the range from 10,000 to 500,000 lbs of steam per hour). Boilers in this size range serve a number of functions for industry: generation of steam or hot water for space heating, process steam, on-site power, or combinations of these.

Efforts to control emissions of nitrogen oxides from industrial boilers by combustion modification may result in operating problems arising from the steps taken to modify the combustion process. The principal problems anticipated are (1) fireside corrosion and deposits on boiler tubes and (2) flame instability.

OBJECTIVES AND SCOPE

The overall objectives of this grant are to assemble background information and to make recommendations in support of research planning on problems associated with combustion modification of industrial boilers. Three separate tasks cover the following areas:

Task A. Information on design features and design trends in industrial boilers, including the composition of the current field population and an assessment of the applicability of combustion modification techniques to various boiler types. Trends in boiler design were assessed by analysis of recent boiler sales in the industrial size range.

Task B. Fireside corrosion and deposits in boilers as affected by combustion modification.

Task C. Flame stability as affected by combustion modifications, including considerations of flame blow-off and combustion-driven oscillations.

A. INDUSTRIAL BOILER POPULATION AND DESIGN TRENDS

Published statistics on industrial boiler installations do not include the detailed breakdown needed to characterize the boiler population, boiler design types, fuel capability, or firing method by capacity range.

To provide this type of information on the current field population for purposes of another EPA contract on commercial boilers, a special survey was made in 1972 by Battelle in cooperation with the American Boiler Manufacturers Association (ABMA). Those data also cover the industrial boiler range and are included in this report as the basis for characterizing the current field population; however, new forecasts of future fuel trends are offered on the basis of more recent developments in the fuel outlook. Trends in boiler design were assessed by analysis of recent boiler sales in the industrial size range.

Recent Sales. Statistics on sales of watertube and firetube boilers were analyzed from ABMA data covering recent years. For watertube boilers, the basic type of boiler design in the larger industrial sizes, ABMA made available computer input data for individual boiler sales recorded during the 8-year period, 1965-1973. Computer summaries were then recorded, considering the following aspects:

- boiler output capacity
- boiler design type
- erection mode, field or shop erected
- fuel capability
- firing method (for coal)
- year of sale
- industrial classification of customer
- region of customer.

Table 1 lists the approximate distribution of recent boiler installations by capacity ranges. Four size classes are identified, covering industrial boiler capacities in the range from 10 to 500 million Btu/hr.

TABLE 1. DISTRIBUTION OF RECENT SALES OF INDUSTRIAL-SIZE BOILERS BY SIZE RANGE

Size Class	Capacity Range, 10^6 Btu/hr	Percent of Industrial Boiler Units	Percent of Total Industrial Capacity	Comment on Predominant Types
A	10-16	35	10	Nearly all are firetube boilers of various types.
B	17-100	53	45	About 75% are watertube boilers, mostly packaged.
C	101-250	11	36	All are watertube boilers, about 70% field erected.
D	251-500	1	9	All are watertube boilers, over 80% field erected.

Detailed tables are included in the report, and general conclusions are summarized for each of these aspects.

Combustion Modifications. An assessment was made of the overall applicability of various boiler designs for combustion modification. Modifications included in the appraisal were the following:

- burner design
- low-excess-air firing
- steam or water injection
- biased firing
- staged combustion
- flue-gas recirculation.

No attempt was made in this study to assess the effectiveness of the modifications in reducing NO_x emissions, as this aspect is being covered in other investigations.

B. FIRESIDE CORROSION AND DEPOSITS AS AFFECTED BY COMBUSTION MODIFICATION

The effects of combustion modifications on boiler corrosion and deposits have been assessed in Task B. Consideration has been given to combustion with low-excess air, two-stage firing, and flue-gas recirculation.

Low-Excess Air. Firing with low-excess air requires that stoichiometric combustion conditions be approached as closely as possible. In the best practice, this has meant that the excess air is maintained at 1 percent (0.2 percent oxygen). With the presently available technology, this condition can only be achieved in oil and gas firing. Low-excess-air combustion essentially eliminates the formation of sulfur trioxide (SO_3) and produces substantial reductions in corrosion. The formation of pyrosulfates and trisulfates in high-temperature zones is minimized, and sulfuric acid corrosion in low-temperature zones is prevented. The formation of low-melting vanadium compounds in residual-oil firing also is inhibited. The benefits of firing with low-excess air are not yet available, to coal-fired systems, and new research needs to be conducted in this area.

Staged Combustion Both the fuel-rich zone and the transition zone in two-stage combustion can be a source of corrosion and deposit problems. Sulfide corrosion is likely to occur in areas that are subject to reducing conditions, because the sulfur in the fuel will not be oxidized to SO_2. This condition is particularly serious in coal-firing, where the pyrites (FeS_2) may not be completely oxidized.

The reducing atmosphere of staged combustion also can lead to potential problems with incompletely oxidized carbon, particularly in the transition zone, where alternating oxidizing and reducing conditions can occur. Formation of carbon monoxide in this zone can result in removal of protective iron oxide layers on boiler tubes. New tube metal will then be oxidized when the conditions reverse, thus accelerating corrosion.

The problems that may result from partially oxidized sulfur and carbon possibly can be overcome by air-management practices. Proper blanketing of vulnerable areas with air would be required to insure that oxidation to CO_2 and SO_2 will occur, without formation of SO_3. The use of special alloy steels with high chromium content that will resist sulfide corrosion and oxidation also offers a potential solution to the problems of staged combustion. Investigation of the use of chrome ore for tube protection also is recommended.

Flue-Gas Recirculation. Flue-gas recirculation can provide the benefits of lowered SO_3, but it can also introduce the problems of partially oxidized sulfur and carbon. Careful design of equipment is required to minimize these potential problems.

R&D Recommendations. Research is needed on several problem areas in burning pulverized coal with low-excess air. To make this approach feasible, it will be necessary to investigate several variables with respect to low-excess-air operation: coal particle size, coal rank, burner design, air-fuel ratio, and type of firing.

Methods for preventing corrosion in (1) sulfide attack under fuel-rich conditions, and (2) metal wastage by alternate oxidizing and reducing conditions should be investigated. An improved corrosion probe concept needs design and development.

C. FLAME STABILITY AS AFFECTED BY COMBUSTION MODIFICATION

Utilizing various combustion modification techniques to control NO_x emissions from industrial boilers can lead to severe flame stability problems. Because flame stability is directly related to the basic fuel parameters of burning velocity and critical velocity gradient, either a change in fuel composition in critical regions in the combustion system or a change in the burner can alter these parameters and affect the stability of a burner-furnace system. The flame stability criteria of a burner-furnace system must not only be considered in relation to traditional terms of flash-back, blow-off, and quenching potential, but also in relation to criteria associated with combustion-induced noise.

In Task C, basic data on flame instability that were available in the literature were applied to industrial-boiler systems to predict the potential of flame instability from combustion modification. A general correlation for predicting the effects of recirculated products at arbitrary temperatures on burning velocity and critical velocity gradient was developed and utilized to predict relative effects of various design changes on the stability limits of a combustion system. It was shown that recirculation without excessive cooling of the recirculated gases could actually increase the maximum firing rate (excluding the effect of increased pressure drop through the heat exchanger). Additional cooling will decrease the limits. The effect of two-stage combustion depends on the details of the furnace-burner system, and may either increase or decrease the operating range. Steam or water injection will decrease the stability limits.

Combustion Noise. Four different types of combustion noise were considered: (1) combustion-driven oscillations, (2) combustion roar, (3) unstable combustion noise generated by the precursor of the blow-off conditions of a flame, and (4) amplified noise of periodic flow phenomena. On the basis of present technology, it was not possible to make specific predictions as to the effects on noise of various combustion modifications; however, several positive conclusions can be drawn.

First, problems of combustion-driven oscillations are common in the development of any new burner-furnace system. The conversion of combustion systems to use of two-stage combustion, recirculation, or other modifications, can be expected to produce some incidence of such problems. However, because of the urgency for trials to investigate combustion modification as a means of NO_x control and the large number of potential conversions of existing units, the problem will be amplified. Second, changes in design that lower the stability limits will increase the incidence of combustion-driven oscillations and the intensity of combustion roar. Third, the use of cooled recirculated products and/or steam will decrease the noise output. Fourth, two-stage combustion will increase combustion roar and the propensity for combustion-driven oscillations.

R&D Recommendations. Although flame-stability and combustion-noise problems can be anticipated when combustion systems for industrial boilers are modified for NO_x control, an awareness of potential problems during engineering design can help to minimize the extent of problems. New R&D directed to these areas can provide a broader design basis for solutions to problems related to stability and noise under conditions of combustion modifications.

Specific research that should be carried out concerns (1) the determination of stability limits data and corresponding predictive rules on industrial-type burners (as contrasted to laboratory burners) using both present fuels and contemplated fuels, (2) experimental determination of acoustic impedance characteristics of furnace and ducting components, (3) experimental determination of basic acoustic spectra of industrial burners using present and contemplated fuels.

PART A

INDUSTRIAL BOILER POPULATION AND DESIGN TRENDS

by

D. W. Locklin and E. L. Kropp
Battelle-Columbus Laboratories

March, 1974

PART A

INDUSTRIAL BOILER POPULATION AND DESIGN TRENDS

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PART A

INDUSTRIAL BOILER POPULATION AND DESIGN TRENDS

by

D. W. Locklin and E. L. Kropp

BATTELLE
Columbus Laboratories

OBJECTIVES OF TASK

Boilers for industrial steam raising are significant users of fossil fuels and, thus, are important in considerations of air-pollution control from stationary sources.

To provide a broader basis for R&D planning directed to the control of air-pollutant emissions from industrial boilers, this task had the following objectives:

1. To characterize the current field population of industrial boilers
2. To identify trends in boiler design
3. To assess the overall applicability of various boiler designs for combustion modifications to control nitrogen oxides.

BACKGROUND AND SCOPE

Definition of Capacity Range for Industrial Boilers

The capacity range typically designated for industrial boilers is from 10 million to 500 million Btu/hr output. This range is larger than "commercial boilers" and smaller than "utility boilers", even though industrial-type boilers are sometimes used for electrical generation by utilities (including municipal utilities and rural cooperatives).

Table A-1 shows this capacity range in other approximately equivalent units of output and fuel input.

TABLE A-1. CAPACITY RANGE FOR INDUSTRIAL BOILERS IN APPROXIMATELY EQUIVALENT UNITS

Capacity Rating	Minimum Capacity	Maximum Capacity
Boiler Output Units		
Btu/hr output	10,000,000	500,000,000
Pounds steam/hr output, PPH(a)	10,000	500,000
Boiler horsepower(b)	300	--
Fuel Input Units(c)		
Oil input gallons/hr	83	4,200
barrels/day	48	2,400
Gas input, cubic feet/hr	12,000	620,000
Coal input, lb/hr	1,000	50,000
tons/day	12	600

a. Based on equivalent output of saturated steam.

b. One boiler horsepower is equivalent to approximately 33,500 Btu/hr output. Boiler horsepower ratings are commonly used for firetube boilers, which are generally available only in sizes up to about 900 boiler horsepower.

c. Assuming full-load operation at 80 percent boiler efficiency and fuel heating value 150,000 Btu/gal for residual oil, 1,000 Btu/cubic foot for natural gas, and 12,500 Btu/lb for coal.

Significance of Industrial Steam Generation

Table A-2 shows the usage of fossil fuels for major industrial applications in comparison to the total usage of all sectors and to the utility sector. Steam generation is the predominant industrial use and is almost as large in fuel consumption as the utility sector.

TABLE A-2. INDUSTRIAL AND UTILITY USE OF FOSSIL FUELS(1)

	Trillions of Btu's for base year 1968			
	All Fossil Fuels	Coal	Oil	Gas
TOTAL - ALL SECTORS	59,639	13,326	26,749	19,564
UTILITY SECTOR TOTAL	11,556	7,130	1,181	3,245
INDUSTRIAL SECTOR TOTAL	19,348	5,616	4,474	9,258
Fuel-Fired in Boilers for Steam Generation				
Process & Space Heating	10,132	2,349	1,986	5,797
Electricity Generated On-site	410	95	80	235
Fuel Used for Direct-Heat Applications (not including purchased electrical energy)	6,604	3,025	808	2,771
Fuel Used as Feedstocks	2,202	147	1,600	455

Boiler firing accounts for 54 percent of industrial-fuel usage; nearly all of this energy input is for steam or hot water used in process or space heating applications, and only a small fraction represents steam for generation of on-site electrical power. In the base year, gas provided approximately 57 percent of the fuel input to boilers for industrial steam generation, with coal and oil contributing 23 and 20 percent, respectively.

Fuel Trends

The coal share of the industrial market has declined steadily in the past few decades, with increasing use of natural gas and oil. The growth of gas usage reflects the recent low cost of gas in many areas and the low capital cost and low operating cost of gas-fired-packaged boilers. The decline in the share of coal reflects, similarly, the high capital and operating cost of coal-fired steam plants which must include coal storage and handling, air-pollution control, and ash disposal. In many new plants these problems are minimized by installing low-cost-packaged boilers to burn gas or oil.

Interest in air-pollution abatement in recent years has also tended to increase conversions of coal-fired plans to gas or to low-sulfur oil, adding to the demand for these clean fuels. However, as clean fuels become less available, it appears probable that the industrial sector will be forced to rely increasingly upon coal and residual oil.

Types of Industrial Boilers

Industrial boilers can be categorized(2) into the following basic types:

- Watertube construction
    - Packaged or shop erected
    - Field erected
- Firetube Construction
    - Packaged Scotch
    - Firebox
    - Horizontal return tubular
    - Miscellaneous types

Design features typical of these types of boilers are discussed and illustrated in references 3 through 7 and will not be described here.

Available Statistical Information

The following discussion provides comments on the availability, use, and limitations of statistical information on industrial boilers from various sources.

Field Population Distribution. Previously published statistics on industrial-boiler installations do not include the level of detailed breakdown as desired to characterize the boiler population on boiler design types, fuel capability, and boiler capacity.

To provide this type of information on the boiler field population for purposes of another EPA investigation on emissions from commercial boilers, a special survey was made in 1972 by Battelle in cooperation with the American Boiler Manufacturers Association (ABMA). That survey covered the entire commercial-industrial-boiler range, and data are included in this report as the basis for characterizing the current field population. The survey also indicated past trends since 1930 and a forecast to 1990. However, new forecasts of future fuel trends are offered in this report to reflect an appraisal of more recent developments in the outlook of fuels availability.

Recent Sales. To identify recent trends, statistics on sales of watertube and firetube boilers were analyzed from ABMA data covering recent years(8). For watertube boilers, the basic type of boiler design in the larger industrial sizes, ABMA has made available their data on boiler sales recorded during the period 1965 through October, 1973. Computer summaries were then made considering the following aspects:

- boiler output capacity
- boiler design type
- erection mode, field or shop erected
- fuel capability
- firing method (for coal)

- year of sale
- industrial classification of customer
- region of customer.

For firetube boilers,(9) sales of packaged-Scotch boilers were analyzed, based on ABMA statistics for the years 1965 to 1972. Packaged-Scotch boilers are the predominant type of firetube boilers in the industrial-size range; however, limited ABMA data provided an estimate of firebox-firetube boilers in this size range.

Inventory of Boiler Installations. Unfortunately, there is no fully satisfactory source of statistics on the actual number or the installed capacity of boilers now in field service. Sales records, even if available for many years, would not be adequate because a field conversion from one fuel to another is not reflected in sales records. Boiler inspectors are the only group that continues to monitor boilers after installation, but they are concerned primarily with the safety of the pressure vessel and do not record details of fuel use or burner fuel in a consistent reporting procedure.

The most comprehensive inventory estimate of boilers from residential to utility size was from an EPA study conducted by Walden(10) which made use of data and estimates from a variety of sources but did not provide breakdowns to characterize the boiler population on a detailed basis. The Walden estimate of total-installed capacity of industrial boilers in 1967 have been updated in this report on the basis of ABMA data. The detailed information characterizing the field population on a percentage basis can be applied to the total inventory estimates to provide an insight as to the total capacity of boilers with features of particular interest.

Power Magazine provides an annual statistical overview of industrial boilers(11), but this is only a partial sampling and is not adequate to provide inventory information. This annual overview offers an opportunity to judge boiler types and installation features, but it was not used in this analysis.

The National Environmental Data System (NEDS) is a new source of information that may prove to be effective in estimating the total inventory of large boilers as the coverage and reporting are improved. This EPA data bank contains limited information on major boiler installations that have been identified as "point sources" in the emission inventories compiled under The Clean Air Act(12). Most states are represented, but several significant industrial states are not yet included.

This system provides information for major installations on the boiler capacity, fuel type, and estimated annual fuel consumption, but no other details are available to characterize the boiler as to design or burner type.

Another limitation is that the lower cut-off point of boiler capacity for reporting may be variable with the practices of the reporting companies, with the inventory-survey teams compiling data for various states, and for different fuels according to an appraisal of annual emissions. These latter criteria could also eliminate boilers which operate as standby or with very low load factor. The inventory is probably more reliable for the largest boilers with high-load factor and with coal-fired boilers where emission factors would be highest.

In view of the foregoing limitations, the NEDS data were not used in this study, except to compare the overall distribution of capacities in coal-fired boilers in the largest sizes(13). However, the NEDS system appears to offer a potential opportunity in the future to provide useful information on an inventory of boilers in the largest sizes and, possibly, to be viewed in conjunction with ABMA data.

OVERALL CONCLUSIONS

An overview of conclusions resulting from the study is presented in this section, covering separately the following aspects:

1. Survey of the current field population and trends
2. Analysis of recent watertube boiler sales installations
3. Analysis of recent firetube boiler sales installations
4. Inventory of installed capacity
5. Applicability of combustion modification to various types of industrial boilers.

The designations in the right-hand margin refer to tables or figures that support the conclusions.

1. Current Field Population of Boiler Trends

The survey conducted for the API/EPA field measurement program included a range of capacity comprising both commercial and industrial boilers(8); the following observations apply to industrial boilers in the capacity range from 10,000 to 500,000 pounds steam per hour (PPH).

Boiler Type

- In the industrial boiler size range, firetube boilers are the dominant construction type in the smaller sizes, accounting for 78 percent of the boilers below 16,000 PPH; many of these are of package design. Watertube boilers are dominant in the size range from 17,000 to 100,000 PPH, accounting for 79 percent of the boilers, mostly package type. Essentially, all boilers above 30,000 PPH in capacity are of watertube construction, with field erection for the larger sizes. A-3

- In the capacity range where firetube and watertube boilers overlap, little trend in sales is apparent in recent years, so the relationship of the two types is expected to hold relatively constant. A-6

Package vs Field-Erected Boilers

- In firetube boilers below 30,000 PPH, packaged Scotch boilers and firebox boilers are most common. Cast-iron boilers are generally not available in the industrial size range. A-3

- The trend in firetube boiler construction is to packaged Scotch boilers. Firebox boilers are expected to hold their present position in smaller size ranges. In watertube construction, the trend is toward packaged boilers and away from field-erected boilers, except in the largest sizes. A-6

Fuels

- Oil and gas firing are dominant over the full range of industrial boilers, with gas firing most prevalent as a prime fuel for the smaller capacity and oil most prevalent at larger capacities. Few boilers in the smaller sizes have coal-firing capability, but the percentage increases to nearly 30 percent in sizes about 250,000 PPH. A-4

- Until the recent situation of fuel shortages, the trend in fuels has been toward oil and gas, with coal projected in the previous survey to decrease even in larger sizes. Revised projections show an increase in coal firing for new installations in all sizes, but especially in capacities above about 100,000 PPH. A-7

- Of the oil-fired installations, residual oil is predominate, mainly heavy No. 5 and No. 6 oil. Distillate oil firing is significant only below about 16,000 PPH, representing only 10 percent of oil firing in this range. (In dual oil/gas burners, distillate oil firing is more common.) A-4

- A trend to distillate oil firing, away from residual oil and coal, has become apparent due to air-pollution considerations. (However, this is likely to reverse for large industrial boilers if fuels become allocated according to priority uses.) A-7

- For larger boilers, a return to coal firing in the near future is likely if supplies of oil and gas continue to be limited. A-7

Oil Burner Types

- Among oil burners, air atomization and rotary atomization are the dominant types in the lowest capacities. Steam atomization is dominant in larger capacities. Pressure atomization is sometimes used in the low capacities. A-5

- Present and forecast trends are away from rotary oil burners and toward air atomizing burners in smaller sizes or steam atomizing in larger sizes. A-8

Coal-Firing Method

- The underfeed stoker is by far the most common coal-firing method in boiler sizes up to about 100,000 PPH. The spreader stoker is popular from 100,000 to 250,000 PPH. Pulverized coal firing is dominant in larger sizes. A-5

- For coal firing of boiler capacities up to 100,000 PPH, the use of spreader stokers is forecast to increase. Pulverized coal firing is expected to become more prevalent in sizes between 100,000 and 250,000 PPH. A-8

Load Factor

- Annual load factor is a measure of boiler service usage reflecting part-load operation; it is the ratio of fuel quantity burned to the quantity that would be burned in full-load operation. Annual load factor varies from about 25 percent for boilers used for space heating to as high as 90 percent for boilers supplying steam for relatively constant-process loads.

2. Recent Sales of Watertube Boilers

The following observations are made from the analysis of ABMA records on watertube sales for the period, 1965 through October 1973.

Capacities

- Most watertube boilers sold were in the lower end of the capacity range. The range up to 100,000 PPH accounts for 76 percent of the watertube boiler units. About 21 percent of the units were in the range 100,000 to 250,000 PPH, and only 21 percent were in the range 250,000 to 500,000 PPH. About 90 percent were in the range up to 250,000 PPH. A-9

- The total capacity of the non-utility watertube boiler was more evenly distributed between ranges. About 44 percent of the watertube capacity was in the range up to 100,000 PPH, about 41 percent was in the range 100,000 to 250,000 PPH, and only 10 percent in the range 250,000 to 500,000 PPH. A-25

- There was a recent increase in the percentage of boiler units in the size category from 250,000 to 500,000 PPH. A-9

Fuels

- Oil and gas were the dominant fuels in boiler sizes up to 500,000 PPH for sales during the past 8 years. Boilers identified with gas or oil firing capability account for 78 percent of all boilers (mostly as dual-fuel units). Boilers with gas listed as primary fuel accounted for 58 percent of the boilers, whereas oil as a primary fuel accounted for only 30 percent. A-10 A-13 A-17

- Coal firing has declined during the period, from 14 percent of the boilers in 1965 to 4 percent in 1972 and 1973. Few new boiler installations have coal-firing capability, except in sizes about 500,000 PPH, where about 50 percent of boilers sold in the 8-year period were coal fired. (In 1973, 92 percent of the boilers ordered in this range were for coal firing.) A-10

- Among other primary fuels (other than oil, gas, or coal), wood waste was the most prevalent of those specifically identified. A substantial number of waste-heat boilers were sold in the range below 100,000 PPH. A-11 A-13

Packaged vs Field-Erected Boilers

- Packaged boilers dominated the number of field-erected boilers in the smaller size range, 9:1 up to 100,000 PPH and 3:1 between 100,000 and 250,000 PPH. The ratio reversed to 1:5 between 250,000 and 500,000 PPH. In larger boilers, nearly all were field erected. A-11 A-18

- 80 percent of oil-fired boilers and 90 percent of gas-fired boilers were package type. Field-erected boilers account for 94 percent of coal-fired boilers. A-18

Firing Method for Coal

- For coal firing, underfeed stokers were the principal firing method for boiler capacities below 16,000 PPH. Spreader stokers dominated the next range to 250,000 PPH, with pulverized coal dominating the larger sizes. A-12

- Exports accounted for only about 2 percent of the boilers during the period, mostly oil fired. A-15

Geographic Distribution of Boilers and Primary Fuels

- The principal concentrations of industrial boiler sales were in the Mid-Atlantic States and the East-North-Central States. Each of these regions accounted for about 23 percent of the boiler sales. The next highest percentage was 17 percent in the South-Atlantic States. A-22

- Gas was the dominant fuel in all regions except the New England States and the Mid-Altantic States; these latter regions had 36 percent gas-fired boilers, compared to 59 percent on a national basis. Gas firing accounted for 72 percent of the boilers in the states west of the Mississippi River and 68 percent in the East-North-Central States. A-22

- Oil was the dominant fuel in the Northeast, where much of industry is relatively accessible by water transportation. Oil firing accounted for 64 percent of the boilers in New England and 50 percent in the Mid-Atlantic States. (This compares to 27 percent on a national basis.) A-22

- Coal firing was strongest in the East-North-Central States, accounting for 42 percent of the coal-fired boilers in the United States and 12 percent of boilers in those states. The Mid-Atlantic States accounted for 18 percent of the coal-fired boilers in the United States. (On a national basis, 7 percent of the boilers were coal fired.) A-22

- Wood waste firing was the only significant nonfossil fuel, representing about 5 percent of the boilers in the two Western regions. A-22

3. Recent Sales of Firetube Boilers

Most of the recent firetube boilers in the industrial size range (about 300 boiler horsepower or 10,000 PPH) are packaged Scotch type. The following observations are based on ABMA records on firetube boiler sales in the commercial-industrial size range for the 8-year period, 1965-1972.

- Boilers of the packaged Scotch type ranged in capacity from 10 to 900 boiler horsepower. The most popular size range was 100 to 300 boiler horsepower. About 14 percent of the Scotch units were in the industrial size range, and about 38 percent of the Scotch capacity was in this size range. A-24 A-25

- As for fuel firing capability, 30 percent of the Scotch boilers were equipped as dual-fuel boilers for oil or gas, 38 percent were equipped for oil only, and 32 percent for gas only. (Scotch firetube boilers are generally not equipped for coal firing.) A-23

- Over the 8-year period, there has been a trend to dual-fuel combination boilers from 24 percent in 1965 to 37 percent in 1972. In 1971 and 1972, units equipped for oil only displaced gas-only units. (In 1972, 41 percent were oil only and 21 percent gas only, and 38 percent combination.) A-23

4. Inventory of Installed Capacity

The following observations were made from an estimate of total capacity of boilers in service within the industrial size range.

- It is estimated that the total installed capacity of industrial watertube and firetube boilers in service at the end of 1972 was nearly 2.5 billion PPH. Of this capacity, 90 percent was watertube construction. A-26

- Of the industrial firetube capacity installed in the past 8 years, 68 percent was in the range 301 to 500 boiler horsepower, and 32 percent in the range above 500 horsepower. A-24

- Of the watertube capacity installed in the past 8 years, 44 percent was in the size range 100,000 PPH and below, 41 percent was in the range 100,000 to 250,000 PPH, and 10 percent was in the range 150,000 PPH to 500,000 PPH. Only 5 percent of the non-utility boilers were above 500,000 PPH. A-25

5. Applicability of Combustion Modification

The following generalizations result from considerations of the applicability of various combustion modifications for NO_x control to different types of industrial boilers, without regard to the relative effectiveness of the modification. A-16

- Water injection can be applied to any type of industrial boiler.

- Except for coal firing, the combustion modifications which are most readily applied to industrial boilers for NO_x control are burner design, low-excess-air firing, and water injection.

- Flue-gas recirculation and staged combustion are feasible in many cases, but with considerable difficulty, for all types of boilers. For stokers, staged combustion can be considered only for new installations.

SURVEY OF FIELD POPULATION OF INDUSTRIAL BOILERS

The most complete information available to characterize the field population of industrial boilers was that developed in connection with planning for the joint API/EPA field measurement program for emissions from commercial boilers.(8) Because industry statistics did not provide the desired detail on boiler and burner features, a special survey of boiler manufacturers was conducted jointly by Battelle and ABMA. Estimates of percentage distributions were requested to enable broad judgements by respondents and provide an overall profile of the present field population.

Tables Summarizing Survey Results

The composite results of that survey are reproduced in the following tables (with revisions by Battelle as identified in the footnotes and as discussed in subsequent text).

Field Population

Breakdowns by capacity ranges of all commercial-industrial boilers now in service in the United States (percentage basis).

Table A-3. By Boiler Types
Table A-4. By Fuel Capability
Table A-5. By Burner Type*

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* Includes revisions on firing method for coal.

Trends

Estimated distribution of features by capacity ranges describing commercial-industrial boilers in service in the United States in years 1930, 1950, 1970, and the forecast for 1990.

Table A-6. By Boiler Types
Table A-7. By Fuel Capability (Revised **)
Table A-8. By Burner Type (Revised ***)

Principal observations from these data were presented in the previous section on "General Conclusions".

** Includes revised projections of fuel use.

*** Includes revisions on firing method for coal.

TABLE A-3. POPULATION BREAKDOWN BY BOILER TYPES (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS NOW IN SERVICE IN U.S.

RATED CAPACITY, SIZE RANGE		Commercial			Industrial			
	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
WATER TUBE								
Industrial Type > 10^4 # Steam/hr		▨	▨	▨	(22)	(79)	(100)	(100)
Packaged		▨	▨	▨	15	55	25	0.5
Field erected		▨	▨	▨	7	24	75	99.5
Commercial Type < 10^4 # Steam/hr		(6)	(8)	(5)	▨	▨	▨	▨
Coil		2	3	2	▨	▨	▨	▨
Firebox		1	1	1	▨	▨	▨	▨
Other		3	4	2	▨	▨	▨	▨
FIRE TUBE								
Packaged Scotch		15	20	30	30	10	▨	▨
Firebox		25	25	30	25	10	▨	▨
Vertical		1	0.5	nil	▨	▨	▨	▨
Horizontal Return Tubular (HRT)		5	10	15	20	1	▨	▨
Misc. (Locomotive type, etc.)		2	3	5	3	nil	▨	▨
CAST IRON		45	33	15	▨	▨	▨	▨
MISC. (Tubeless, etc.)		1	0.5	nil	▨	▨	▨	▨
TOTAL COMMERCIAL-INDUSTRIAL BOILERS		100%	100%	100%	100%	100%	100%	

TABLE A-4. POPULATION BREAKDOWN BY FUEL CAPABILITY (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS NOW IN SERVICE

		Commercial			Industrial			
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
FUELS								
Oil Only		42	42	40	35	35	30	22
Gas Only		50	50	50	45	35	22	22
Coal Only		2	1	1	3	10	18	22
Oil & Gas and Gas & Oil		5	6	8	16	18	26	23
Oil & Coal and Coal & Oil		▨	▨	▨	▨	▨	0.5	3
Gas & Coal and Coal & Gas		▨	▨	▨	▨	▨	0.5	3
Misc. Fuels (alone or with alternate fuels)		1	1	1	1	2	3	5
Total		100%	100%	100%	100%	100%	100%	100%
OIL								
Distillate, No. 2		95	85	50	10	2	2	2
Resid		(5)	(15)	(50)	(90)	(98)	(98)	(98)
No. 4 and Light No. 5 (No preheat)		4.5	14	30	20	2	nil	nil
Heavy No. 5 and No. 6 (Preheated)		0.5	1	20	70	96	98	98
Total Oil		100%	100%	100%	100%	100%	100%	100%

TABLE A-5. POPULATION BREAKDOWN BY BURNER TYPE (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS NOW IN SERVICE IN U. S.

RATED CAPACITY, SIZE RANGE		Commercial			Industrial			
	10^6 Btu/hr or 10^3 lb stm/hr				10-16	17-100	101-250	251-500
	Boiler Horsepower	10-50	51-100	101-300	301-500			
OIL BURNERS (approx. gph)		3-15	15-30	30-90	90-150	150-900	900-2250	2250-4500
Air Atomizing		15	35	40	40	15	5	1
Steam Atomizing		▨	▨	▨	20	70	85	94
Pressure or Mechanical Atomizing		70	25	20	10	10	10	5
Rotary		15	40	40	30	5	▨	▨
Total Oil		100%	100%	100%	100%	100%	100%	100%
COAL BURNERS (approx. lb/hr)		33-160	160-330	330-1000	1000-1600	1600-10,000	10,000-25,000	25,000-50,000
Spreader		nil	5	10	15	20	50	30
Underfeed		90	80	75	70	60	20	15
Overfeed		5	10	10	10	15	10	10
Pulverized		▨	▨	▨	▨	▨	15	40
Other (Hand-firing, Miscellaneous, and Unreported)		5	5	5	5	5	5	5
Total Coal		100%	100%	100%	100%	100%	100%	100%

TABLE A-6. ESTIMATED TRENDS OF BOILER TYPES (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS INSTALLED IN YEARS NOTED

RATED CAPACITY, SIZE RANGE	Commercial												Industrial															
10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-500			
Boiler Horsepower	10-50				51-100				101-300				301-500															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
WATER TUBE																												
Industrial Type > 10^4 # Steam/Hr	—	—	—	—	—	—	—	—	—	—	—	—	(25)	(17)	(19)	(20)	(94)	(97)	(94)	(90)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Packaged	—	—	—	—	—	—	—	—	—	—	—	—	0	2	18	20	0	8	80	89	0	0	80	90	0	0	1	20
Field erected	—	—	—	—	—	—	—	—	—	—	—	—	25	15	1	0	94	89	14	1	100	100	20	10	100	100	99	80
Commercial Type < 10^4 # Steam/Hr	(13)	(15)	(16)	(21)	(13)	(16)	(16)	(12)	(5)	(11)	(10)	(14)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Coil	nil	2	3	5	nil	3	5	4	nil	3	4	5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Firebox	8	5	3	1	8	5	3	1	3	3	4	5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Other	5	8	10	15	5	8	8	7	2	5	2	4	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
FIRE-TUBE																												
Packaged Scotch	nil	10	11	10	1	14	22	26	2	21	41	40	nil	35	40	45	nil	2	5	9	—	—	—	—	—	—	—	—
Firebox	6	11	18	20	20	15	17	23	20	30	35	30	20	40	40	35	1	1	1	1	—	—	—	—	—	—	—	—
Vertical	5	6	6	6	3	5	3	2	5	2	nil	nil	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Horizontal Return Tubular (HRT)	5	1	nil	nil	5	2	nil	nil	60	25	1	nil	50	5	nil	nil	5	4	nil	nil	—	—	—	—	—	—	—	—
Misc. (Locomotive type, etc.)	8	5	3	2	5	1	1	1	8	5	2	nil	5	3	1	nil	nil	nil	nil	nil	—	—	—	—	—	—	—	—
CAST IRON	60	50	45	40	50	45	40	36	nil	5	10	15	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
MISC (TUBELESS, ETC)	3	2	1	1	3	2	1	nil	nil	1	1	1	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
TOTAL COMMERCIAL-INDUSTRIAL BOILERS	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%				%				%				%		

TABLE A-7. ESTIMATED TRENDS BY FUEL CAPABILITY (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS INSTALLED IN YEARS NOTED, INCLUDING CONVERSIONS

	Commercial												Industrial															
RATED CAPACITY, SIZE RANGE: 10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-500			
Boiler Horsepower	10-50				51-100				101-300				301-600															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
FUEL CAPABILITY																												
Oil Only	20	40	30	20	10	30	25	10	10	40	30	10	17	43	30	13	13	30	30	10	5	20	24	nil	5	15	20	nil
Gas Only	10	30	45	25	10	30	38	10	5	25	30	5	5	20	30	6	10	30	30	4	5	20	24	nil	5	15	20	nil
Coal Only	65	20	5	10	75	15	5	15	80	10	5	20	75	10	5	30	75	30	5	40	90	38	15	50	90	60	20	60
Oil & Gas and Gas & Oil	nil	5	18	40	nil	10	30	60	nil	20	30	60	nil	25	30	45	nil	5	30	40	nil	10	25	30	nil	5	20	20
Oil & Coal and Coal & Oil	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	nil	5	5	10	nil	3	10	10
Gas & Coal and Coal & Gas	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	nil	5	5	5	nil	2	10	5
Misc. fuels (alone or with alternate fuels)	5	5	2	5	5	5	2	5	5	5	5	5	3	2	5	6	2	5	5	6	nil	2	2	5	nil	nil	nil	5
Total	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%				%				%				%	
OIL																												
Distillate, No. 2	40	50	70	100	20	30	40	70	10	10	20	40	5	2	10	30	nil	nil	10	20	nil	nil	5	10	nil	nil	5	10
Resid	(60)	(50)	(30)	(nil)	(80)	(70)	(60)	(30)	(90)	(90)	(80)	(60)	(95)	(98)	(90)	(70)	(100)	(100)	(90)	80	(100)	(100)	(95)	(90)	(100)	(100)	(95)	(90)
No. 4 & Light No. 5 (No preheat)	40	40	25	nil	50	50	50	30	30	40	30	5	20	23	10	nil	nil	5	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Heavy No. 5 & No. 6 (Preheated)	20	10	5	nil	30	20	10	nil	60	50	50	55	75	75	80	70	100	95	90	80	100	100	95	90	100	100	95	90
Total Oil	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%				%				%				%	

TABLE A-8. ESTIMATED TRENDS BY BURNER TYPE (PERCENTAGE BASIS) FOR ALL COMMERCIAL-INDUSTRIAL BOILERS INSTALLED IN YEARS NOTED (INCLUDING CONVERSIONS)

RATED CAPACITY, SIZE RANGE	Commercial												Industrial															
10^6 Btu/hr or 10^3 lb stm/hr													10-16				17-100				101-250				251-600			
Boiler Horsepower	10-50				51-100				101-300				301-600															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
OIL BURNERS																												
Air Atomizing	10	15	15	15	15	20	30	30	20	30	55	60	10	20	35	40	5	3	2	1	2	1	nil	nil	2	1	nil	nil
Steam Atomizing	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	30	30	35	40	75	80	88	90	93	94	95	95	93	94	95	95
Pressure or Mechanical Atomizing	70	75	85	85	55	60	65	70	50	40	40	40	25	20	20	20	15	14	10	9	5	5	5	5	5	5	5	5
Rotary	20	10	nil	nil	30	20	5	nil	30	30	5	nil	35	30	10	nil	5	3	nil	nil	▨	▨	▨	▨	▨	▨	▨	▨
Total Oil	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%				%				%				%		
COAL BURNER																												
Spreader	nil	nil	nil	nil	nil	5	10	20	nil	10	20	25	nil	10	25	35	nil	40	50	65	nil	50	60	35	nil	25	10	5
Underfeed	50	95	95	95	50	60	75	70	55	65	70	70	60	60	70	50	60	25	15	10	50	20	nil	nil	25	10	nil	nil
Overfeed	nil	nil	nil	nil	40	30	10	5	35	20	10	5	35	25	nil	10	35	30	25	15	45	15	10	10	60	10	nil	nil
Pulverized	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	nil	10	20	40	10	50	80	85
Other (including refuse, sawdust, and wood)	50	5	5	5	10	5	5	5	10	5	5	5	5	5	5	5	5	5	5	10	5	5	10	15	5	5	10	10
Total Coal	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%				%				%				%		

Revisions From Previous Survey

The following comments refer to the revisions made in the summary of the previous survey of field population and sales trends.(8)

Fuel Projections. In Table A-7, the projection of fuels for the year 1990 were revised by Battelle to reflect changes in availability of fuels which might be expected in light of the overall energy situation. The projections were made on a judgmental basis, with the following broad assumptions:

1. That oil and gas supplies will be limited
2. That oil and gas will be utilized in smaller equipment and for high-priority uses (but not by 100-percent mandatory allocation)
3. That coal will dominate new installations in the larger sizes
4. That clean liquid and gaseous fuels from coal conversion processes will not be available in large quantities by 1990
5. That firing of any available supply of SNG or low-Btu gas will be included in the estimate for gas firing, and any available supplies of liquid fuels from coal will be included in the estimates for oil firing. (Pulverized firing of chemically refined solid fuels will be included under coal firing)
6. Refuse firing as a supplementary fuel will increase, but will not become significant in terms of percentages.

Firing Method. The information on firing method for coal and other solid fuels was revised for Tables A-5 and A-8. These estimates were made judgmentally, based on the analysis of recent sales data for watertube boilers (reported in a subsequent section of this report), plus overall judgment of Battelle and ABMA staff familiar with solid fuel firing.

Load Factors. Most industrial boilers do not operate continuously at full load. Load factor (or usage factor) is of interest to allow estimates of fuel use where this is necessary. Load factor is defined as the ratio of actual fuel used per year to the calculated usage per year at constant full-load operation. The following provides information on typical load factors for boilers serving different functions:

Type of Load	Typical Range for Range Factor, percent
Space heating	20-30
General commercial uses	30-60
General industrial uses	50-80
Industrial processing	75-90
Power generation	10-90

An analysis of large coal-fired industrial boilers in the NEDS data bank revealed an average load factor of about 55 percent.(13).

ABMA records of watertube boiler sales during the last 8 years were analyzed. Through a special agreement for purposes of this EPA grant, ABMA made available to Battelle their data file on watertube boiler sales for the years 1965 through October, 1973. These records were in the form of computer cards for each boiler sale, coded with detailed information concerning boiler capacity, erection method, fuels, industrial classification of customer, and other data as noted below.

Information Analyzed

- Capacity Per Unit:

  Boiler capacity reported in thousands pounds of steam per hour as the maximum capacity when fired with primary fuel.

  To facilitate comparison with the field population survey, Battelle aggregated individual boiler capacities into five boiler capacity categories as follows:

  A. 10 to 16 KPH*
  B. 17 to 100 KPH
  C. 101 to 250 KPH
  D. 250 to 500 KPH
  E. Over 500 KPH
  (generally utility boilers)

- Primary Fuel:
  - Bituminous Coal
  - Oil
  - Natural Gas
  - Wood, Bark, or Solid Wood
  - Bagasse
  - Black Liquor
  - Other Fuels
  - Wasteheat
  - Wasteheat, auxiliary firing
  - Lignite
  - Raw Municipal, unsorted
  - Raw Municipal, non-combustible removed
  - Raw Municipal, sorted & sized
  - Other Industrial Waste

---

* Boiler capacity categories in the statistical tables which follow are in thousand pounds of steam per hour rated output (KPH).

- Alternate or Auxiliary Fuel:

  Same as list above for primary fuel

- Firing Method:
  - Pulverized coal
  - Spreader stoker
  - Underfeed stoker
  - Overfeed stoker
  - Other solid fuel firing
  - Gas turbine or engine exhaust
  - Other non-combustible waste gas
  - Combustible waste gas
  - Non-solid fuel firing

- Packaged or Field Assembled:*
  - Pressure vessel completely shop assembled
  - Pressure vessel shop assembled and shipped as two, three, four, five, or six major modules
  - Packaged design shipped knocked-down
  - Field assembled, bottom supported
  - Field assembled, top supported

- Standard Industrial Classification Number

- Domestic or Export

- Geographic Region (by number code as follows:)

  1. New England States
     Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
  2. Mid-Atlantic States
     Delaware, Maryland, New Jersey, New York, Pennsylvania, Virginia, West Virginia
  3. East-North-Central States
     Illinois, Indiana, Kentucky, Michigan, Ohio, Wisconsin
  4. South-Atlantic States
     Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, Tennessee
  5. West-North-Central States
     Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
  6. West-South-Central States
     Arkansas, Louisiana, Oklahoma, Texas
  7. Rocky Mountain States
     Colorado, New Mexico, Utah, Wyoming

---

* For purposes of the analysis for method of erection, all boilers were considered "packaged boilers", except those identified as "field assembled".

8. Northwestern States
   Idaho, Montana, Oregon, Washington
9. Southwestern States
   Arizona, California, Nevada

Explanation of Summary Tables From Analysis

The computer program used to summarize the information on recent sales of watertube boilers was the SPSS statistical package*. SPSS contains subprograms which allow the examination of relationships between variables in a table-type format. They permit display of frequency distributions with varying levels of control variables. The following explanation applies to Tables A-9 through A-22.

Table Format. The body of each table contains blocks with numerical information. The upper left corner of the table describes what the numbers represent; e.g., COUNT is the number of boilers in the block; ROW PCT is the row percentage of a given block of the total number in the row; COL PCT is the column percentage of a given block of the total number in the column; and TOT PCT is the percentage of a given block of the total number in the table.

The phrase "Number of missing observations = n" may appear at the bottom of the table. This means that of the total cases examined for a table, there were some cases for which either a row variable or a column variable was missing, so that the case could not be classified.

---

* SPSS is a set of commercial computer programs available from Vegelback Computing Center, Northwestern University. (13)

Tables A-9 through A-22 are in the format described above and present statistical analyses for the following cases:

Table	Pages	Description of Tables				
A-9	31	Capacity Category	By	Year	For	All WT Boilers
A-10	32-39	Capacity Category	By	Year	For	Each Primary or Alternate Fuel
A-11	40	Erection Method	By	Capacity Category	For	WT Boilers
A-12	41-43	Firing Method	By	Capacity Category	For	Solid Fuels
A-13	44-45	Primary Fuel	By	Capacity Category	For	WT Boilers
A-14	46-47	Alternate Fuel	By	Capacity Category	For	WT Boilers
A-15	48	Primary Fuel	By	Capacity Category	For	Exported WT Boilers
A-16	49-52	Primary Fuel	By	Year	For	WT Boilers
A-17	53-54	Primary Fuel	By	Alternate Fuel	For	WT Boilers
A-18	55	Erection Method	By	Primary Fuel	For	WT Boilers
A-19	56	Erection Method	By	Year	For	WT Boilers
A-20	57-61	Firing Method	By	Year	For	Each WT Capacity Category
A-21	62-69	Primary Fuel	By	SIC Code	For	WT Boilers
A-22	70-71	Primary Fuel	By	Geographic Region	For	WT Boilers

TABLE A-9. BOILER CAPACITY CATEGORY BY YEAR FOR WATERTUBE BOILERS

BOILER CAP. CATEGORY	COUNT ROW PCT COL PCT TOT PCT	YEAR SOLD 65	66	67	68	69	70	71	72	73	ROW TOTAL
10-16KPH	1	108	99	54	56	65	35	40	44	15	516
		20.9	19.2	10.5	10.9	12.6	6.9	7.8	8.5	2.9	5.8
		9.3	7.8	5.8	6.2	5.8	3.5	3.8	4.3	3.2	
		1.2	1.1	0.6	0.6	0.7	0.4	0.4	0.5	0.2	
16-100KPH	2	800	874	657	696	753	663	704	709	303	6159
		13.0	14.2	10.7	11.3	12.2	10.8	11.4	11.5	4.9	68.8
		68.9	69.1	70.3	76.8	67.4	66.2	66.5	68.6	64.2	
		8.9	9.8	7.3	7.8	8.4	7.4	7.9	7.9	3.4	
100-250KPH	3	128	186	130	154	207	193	226	172	90	1486
		8.6	12.5	8.7	10.4	13.9	13.0	15.2	11.6	6.1	16.6
		11.0	14.7	13.9	17.0	18.5	19.3	21.4	16.6	19.1	
		1.4	2.1	1.5	1.7	2.3	2.2	2.5	1.9	1.0	
250-500KPH	4	54	41	24	0	35	34	25	46	39	298
		18.1	13.8	8.1	0.0	11.7	11.4	8.4	15.4	13.1	3.3
		4.7	3.2	2.6	0.0	3.1	3.4	2.4	4.4	8.3	
		0.6	0.5	0.3	0.0	0.4	0.4	0.3	0.5	0.4	
500+KPH	8	71	64	59	0	57	77	68	68	25	489
		14.5	13.1	14.1	0.0	11.7	15.7	12.9	12.9	5.1	5.5
		6.1	5.1	7.4	0.0	5.1	7.7	5.0	6.1	5.3	
		6.8	0.7	0.8	0.0	0.6	0.9	0.7	0.7	0.3	
	COLUMN TOTAL	1161	1264	934	906	1117	1002	1058	1034	472	8948
		13.0	14.1	10.4	10.1	12.5	11.2	11.8	11.6	5.3	100.0

NUMBER OF MISSING OBSERVATIONS = 75

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL -- BITUMINOUS COAL

```
                          YEAR  SOLD
                 COUNT  I                              BITUMINOUS COAL
                 ROW PCT I                                                                                  ROW
                 COL PCT I                                                                                  TOTAL
BOILER CAPACITY  TOT PCT I   65   I   66   I   67   I   68   I   69   I   70   I   71   I   72   I   73   I
  CATEGORY       --------I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                       1 I     3  I     2  I     4  I     1  I     0  I     0  I     0  I     0  I     0  I    10
  10-16KPH               I  30.0  I  20.0  I  40.0  I  10.0  I   0.0  I   0.0  I   0.0  I   0.0  I   0.0  I   1.6
                         I   1.8  I   1.5  I   5.0  I   2.5  I   0.0  I   0.0  I   0.0  I   0.0  I   0.0  I
                         I   0.5  I   0.3  I   0.7  I   0.2  I   0.0  I   0.0  I   0.0  I   0.0  I   0.0  I
                        -I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                       2 I    76  I    61  I    32  I    25  I    17  I     9  I     2  I     1  I     3  I   226
  16-100KPH              I  33.6  I  27.0  I  14.2  I  11.1  I   7.5  I   4.0  I   0.9  I   0.4  I   1.3  I  36.9
                         I  45.8  I  45.9  I  40.0  I  62.5  I  32.1  I  23.7  I   6.1  I   2.7  I   9.4  I
                         I  12.4  I  10.0  I   5.2  I   4.1  I   2.8  I   1.5  I   0.3  I   0.2  I   0.5  I
                        -I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                       3 I    25  I    27  I    10  I    14  I     4  I     5  I     8  I     8  I     5  I   106
  100-250KPH             I  23.6  I  25.5  I   9.4  I  13.2  I   3.8  I   4.7  I   7.5  I   7.5  I   4.7  I  17.3
                         I  15.1  I  20.3  I  12.5  I  35.0  I   7.5  I  13.2  I  24.2  I  21.6  I  15.6  I
                         I   4.1  I   4.4  I   1.6  I   2.3  I   0.7  I   0.8  I   1.3  I   1.3  I   0.8  I
                        -I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                       4 I    15  I     6  I     1  I     0  I     2  I     3  I     1  I     2  I     1  I    31
  250-500KPH             I  48.4  I  19.4  I   3.2  I   0.0  I   6.5  I   9.7  I   3.2  I   6.5  I   3.2  I   5.1
                         I   9.0  I   4.5  I   1.3  I   0.0  I   3.8  I   7.9  I   3.0  I   5.4  I   3.1  I
                         I   2.5  I   1.0  I   0.2  I   0.0  I   0.3  I   0.5  I   0.2  I   0.3  I   0.2  I
                        -I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                       5 I    47  I    37  I    33  I     0  I    30  I    21  I    22  I    26  I    23  I   239
  500+KPH                I  19.7  I  15.5  I  13.8  I   0.0  I  12.6  I   8.8  I   9.2  I  10.9  I   9.6  I  39.1
                         I  28.3  I  27.8  I  41.3  I   0.0  I  56.6  I  55.3  I  66.7  I  70.3  I  71.9  I
                         I   7.7  I   6.0  I   5.4  I   0.0  I   4.9  I   3.4  I   3.6  I   4.2  I   3.8  I
                        -I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                  COLUMN     166      133       80       40       53       38       33       37       32      612
                   TOTAL    27.1     21.7     13.1      6.5      8.7      6.2      5.4      6.0      5.2    100.0

  NUMBER OF MISSING OBSERVATIONS =       4
```

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) — — OIL

```
                          YEAR   SOLD
                   COUNT  I                                   OIL
                 ROW PCT  I                                                                                      ROW
                 COL PCT  I                                                                                      TOTAL
BOILER CAPACITY  TOT PCT  I    65   I    66   I    67   I    68   I    69   I    70   I    71   I    72   I    73   I
   CATEGORY       --------I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                       1  I    89   I    83   I    44   I    43   I    51   I    32   I    32   I    35   I    21   I   430
    10-16KPH              I  20.7   I  19.3   I  10.2   I  10.0   I  11.9   I   7.4   I   7.4   I   8.1   I   4.9   I   6.2
                          I  11.5   I   9.6   I   6.6   I   6.2   I   6.2   I   3.9   I   3.6   I   4.0   I   3.6   I
                          I   1.3   I   1.2   I   0.6   I   0.6   I   0.7   I   0.5   I   0.5   I   0.5   I   0.3   I
                         -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                       2  I   563   I   655   I   509   I   559   I   598   I   563   I   621   I   629   I   425   I  5122
    16-100KPH             I  11.0   I  12.8   I   9.9   I  10.9   I  11.7   I  11.0   I  12.1   I  12.3   I   8.3   I  73.4
                          I  73.0   I  75.6   I  75.9   I  80.3   I  72.2   I  69.0   I  70.4   I  72.7   I  72.6   I
                          I   8.1   I   9.4   I   7.3   I   8.0   I   8.6   I   8.1   I   8.9   I   9.0   I   6.1   I
                         -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                       3  I    67   I    89   I    74   I    94   I   135   I   156   I   177   I   137   I   101   I  1030
    100-250KPH            I   6.5   I   8.6   I   7.2   I   9.1   I  13.1   I  15.1   I  17.2   I  13.3   I   9.8   I  14.8
                          I   8.7   I  10.3   I  11.0   I  13.5   I  16.3   I  19.1   I  20.1   I  15.8   I  17.3   I
                          I   1.0   I   1.3   I   1.1   I   1.3   I   1.9   I   2.2   I   2.5   I   2.0   I   1.4   I
                         -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                       4  I    23   I    18   I    15   I     0   I    20   I    17   I    17   I    30   I    22   I   162
    250-500KPH            I  14.2   I  11.1   I   9.3   I   0.0   I  12.3   I  10.5   I  10.5   I  18.5   I  13.6   I   2.3
                          I   3.0   I   2.1   I   2.2   I   0.0   I   2.4   I   2.1   I   1.9   I   3.5   I   3.8   I
                          I   0.3   I   0.3   I   0.2   I   0.0   I   0.3   I   0.2   I   0.2   I   0.4   I   0.3   I
                         -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                       5  I    29   I    21   I    29   I     0   I    24   I    48   I    35   I    34   I    16   I   236
    500+KPH               I  12.3   I   8.9   I  12.3   I   0.0   I  10.2   I  20.3   I  14.8   I  14.4   I   6.8   I   3.4
                          I   3.8   I   2.4   I   4.3   I   0.0   I   2.9   I   5.9   I   4.0   I   3.9   I   2.7   I
                          I   0.4   I   0.3   I   0.4   I   0.0   I   0.3   I   0.7   I   0.5   I   0.5   I   0.2   I
                         -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
                  COLUMN       771       896       671       696       828       816       882       865       585      6980
                   TOTAL      11.0      12.4       9.6      10.0      11.9      11.7      12.6      12.4       8.4     100.0

  NUMBER OF MISSING OBSERVATIONS =      62
```

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) -- NATURAL GAS

BOILER CAPACITY CATEGORY	COUNT ROW PCT COL PCT TOT PCT	YEAR SOLD 65	NATURAL GAS 66	67	68	69	70	71	72	73	ROW TOTAL
10-16KPH	1	75 20.0 10.4 1.2	71 18.9 8.6 1.2	37 9.9 5.7 0.6	30 8.0 4.6 0.5	45 12.0 5.5 0.7	32 8.5 4.4 0.5	29 7.7 4.4 0.5	40 10.7 6.1 0.6	16 4.3 3.5 0.3	375 6.1
16-100KPH	2	514 11.3 71.6 8.3	585 12.9 71.3 9.5	462 10.6 74.3 7.8	537 11.8 81.7 8.7	598 13.1 73.0 9.7	520 11.4 71.3 8.4	490 10.8 74.6 7.9	507 11.1 76.8 8.2	318 7.0 69.3 5.2	4551 73.8
100-250KPH	3	80 8.6 11.1 1.3	124 13.3 15.1 2.0	83 8.9 12.8 1.3	90 9.7 13.7 1.5	137 14.7 16.7 2.2	132 14.2 18.1 2.1	111 11.9 16.9 1.8	88 9.5 13.3 1.4	85 9.1 18.5 1.4	930 15.1
250-500KPH	4	28 18.1 3.9 0.5	21 13.5 2.6 0.3	12 7.7 1.8 0.2	0 0.0 0.0 0.0	21 13.5 2.6 0.3	14 9.0 1.9 0.2	10 6.5 1.5 0.2	18 11.6 2.7 0.3	31 20.0 6.8 0.5	155 2.5
500+KPH	5	21 13.3 2.9 0.3	20 12.7 2.4 0.3	35 22.2 5.4 0.6	0 0.0 0.0 0.0	18 11.4 2.2 0.3	31 19.6 4.3 0.5	17 10.8 2.6 0.3	7 4.4 1.1 0.1	9 5.7 2.0 0.1	158 2.6
	COLUMN TOTAL	718 11.6	821 13.3	649 10.5	657 10.7	819 13.3	729 11.8	657 10.7	660 10.7	459 7.4	6169 100.0

NUMBER OF MISSING OBSERVATIONS = 52

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) - - WOOD WASTE

WOODWASTE

BOILER CAPACITY CATEGORY	YEAR SOLD COUNT ROW PCT COL PCT TOT PCT	65	66	67	68	69	70	71	72	73	ROW TOTAL
10-16KPH	1	1	1	0	0	1	0	0	0	0	3
		33.3	33.3	0.0	0.0	33.3	0.0	0.0	0.0	0.0	1.8
		5.6	12.5	0.0	0.0	4.8	0.0	0.0	0.0	0.0	
		0.6	0.6	0.0	0.0	0.6	0.0	0.0	0.0	0.0	
16-100KPH	2	13	7	4	6	13	6	14	21	38	122
		10.7	5.7	3.3	4.9	10.7	4.9	11.5	17.2	31.1	73.9
		72.2	87.5	50.0	50.0	61.9	75.0	82.4	75.0	84.4	
		7.9	4.2	2.4	3.6	7.9	3.6	8.5	12.7	23.0	
100-250KPH	3	2	0	1	6	5	1	3	5	5	28
		7.1	0.0	3.6	21.4	17.9	3.6	10.7	17.9	17.9	17.0
		11.1	0.0	12.5	50.0	23.8	12.5	17.6	17.9	11.1	
		1.2	0.0	0.6	3.6	3.0	0.6	1.8	3.0	3.0	
250-500KPH	4	1	0	2	0	1	0	0	0	1	5
		20.0	0.0	40.0	0.0	20.0	0.0	0.0	0.0	20.0	3.0
		5.6	0.0	25.0	0.0	4.8	0.0	0.0	0.0	2.2	
		0.6	0.0	1.2	0.0	0.6	0.0	0.0	0.0	0.6	
500+KPH	5	1	0	1	0	1	1	0	2	1	7
		14.3	0.0	14.3	0.0	14.3	14.3	0.0	28.6	14.3	4.2
		5.6	0.0	12.5	0.0	4.8	12.5	0.0	7.1	2.2	
		0.6	0.0	0.6	0.0	0.6	0.6	0.0	1.2	0.6	
	COLUMN TOTAL	18	8	8	12	21	8	17	28	45	165
		10.9	4.8	4.8	7.3	12.7	4.8	10.3	17.0	27.3	100.0

NUMBER OF MISSING OBSERVATIONS = 1

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) - - BAGASSE

BOILER CAPACITY CATEGORY		COUNT ROW PCT COL PCT TOT PCT	YEAR SOLD 65	BAGASSE 66	68	69	70	71	72	73	ROW TOTAL
16-100KPH	2	COUNT	2	0	3	1	2	5	6	4	23
		ROW PCT	8.7	0.0	13.0	4.3	8.7	21.7	26.1	17.4	52.3
		COL PCT	100.0	0.0	100.0	16.7	66.7	50.0	66.7	44.4	
		TOT PCT	4.5	0.0	6.8	2.3	4.5	11.4	13.6	9.1	
100-250KPH	3	COUNT	0	2	0	4	1	5	3	4	19
		ROW PCT	0.0	10.5	0.0	21.1	5.3	26.3	15.8	21.1	43.2
		COL PCT	0.0	100.0	0.0	66.7	33.3	50.0	33.3	44.4	
		TOT PCT	0.0	4.5	0.0	9.1	2.3	11.4	6.8	9.1	
250-500KPH	4	COUNT	0	0	0	0	0	0	0	1	1
		ROW PCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	2.3
		COL PCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	
		TOT PCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	
500+KPH	5	COUNT	0	0	0	1	0	0	0	0	1
		ROW PCT	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	2.3
		COL PCT	0.0	0.0	0.0	16.7	0.0	0.0	0.0	0.0	
		TOT PCT	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.0	
COLUMN TOTAL			2	2	3	6	3	10	9	9	44
			4.5	4.5	6.8	13.6	6.8	22.7	20.5	20.5	100.0

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) - - BLACK LIQUOR

BOILER CAPACITY CATEGORY		COUNT ROW PCT COL PCT TOT PCT	YEAR SOLD 65	BLACK LIQUOR 66	67	68	69	70	71	72	73	ROW TOTAL
16-100KPH	2		2	1	1	4	1	0	0	2	2	13
			15.4	7.7	7.7	30.8	7.7	0.0	0.0	15.4	15.4	11.4
			10.5	6.7	25.0	66.7	8.3	0.0	0.0	11.1	13.3	
			1.8	0.9	0.9	3.5	0.9	0.0	0.0	1.8	1.8	
100-250KPH	3		7	5	2	2	2	2	6	5	5	36
			19.4	13.9	5.6	5.6	5.6	5.6	16.7	13.9	13.9	31.6
			36.8	33.3	50.0	33.3	16.7	22.2	37.5	27.8	33.3	
			6.1	4.4	1.8	1.8	1.8	1.8	5.3	4.4	4.4	
250-500KPH	4		10	7	1	0	8	3	9	6	7	51
			19.6	13.7	2.0	0.0	15.7	5.9	17.6	11.8	13.7	44.7
			52.6	46.7	25.0	0.0	66.7	33.3	56.3	33.3	46.7	
			8.8	6.1	0.9	0.0	7.0	2.6	7.9	5.3	6.1	
500+KPH	5		0	2	0	0	1	4	1	5	1	14
			0.0	14.3	0.0	0.0	7.1	28.6	7.1	35.7	7.1	12.3
			0.0	13.3	0.0	0.0	8.3	44.4	6.3	27.8	6.7	
			0.0	1.8	0.0	0.0	0.9	3.5	0.9	4.4	0.9	
COLUMN TOTAL			19	15	4	6	12	9	16	18	15	114
			16.7	13.2	3.5	5.3	10.5	7.9	14.0	15.8	13.2	100.0

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) - - OTHER FUELS

BOILER CAPACITY CATEGORY	YEAR SOLD COUNT ROW PCT COL PCT TOT PCT	65	66	67	68	69	70	71	72	73	ROW TOTAL
		OTHER FUELS									
10-16KPH	1	3	3	2	8	1	0	1	0	0	18
		16.7	16.7	11.1	44.4	5.6	0.0	5.6	0.0	0.0	4.1
		3.8	2.8	3.3	17.8	1.9	0.0	5.6	0.0	0.0	
		0.7	0.7	0.5	1.8	0.2	0.0	0.2	0.0	0.0	
16-100KPH	2	45	48	29	25	18	6	5	4	3	183
		24.6	26.2	15.8	13.7	9.8	3.3	2.7	2.2	1.6	41.8
		57.0	44.9	48.3	55.6	34.6	33.3	27.8	18.2	8.1	
		10.3	11.0	6.6	5.7	4.1	1.4	1.1	0.9	0.7	
100-250KPH	3	20	40	19	12	21	8	8	12	16	156
		12.8	25.6	12.2	7.7	13.5	5.1	5.1	7.7	10.3	35.6
		25.3	37.4	31.7	26.7	40.4	44.4	44.4	54.5	43.2	
		4.6	9.1	4.3	2.7	4.8	1.8	1.8	2.7	3.7	
250-500KPH	4	7	15	7	0	9	4	3	2	18	65
		10.8	23.1	10.8	0.0	13.8	6.2	4.6	3.1	27.7	14.8
		8.9	14.0	11.7	0.0	17.3	22.2	16.7	9.1	48.6	
		1.6	3.4	1.6	0.0	2.1	0.9	0.7	0.5	4.1	
500+KPH	5	4	1	3	0	3	0	1	4	0	16
		25.0	6.3	18.7	0.0	18.7	0.0	6.3	25.0	0.0	3.7
		5.1	0.9	5.0	0.0	5.8	0.0	5.6	18.2	0.0	
		0.9	0.2	0.7	0.0	0.7	0.0	0.2	0.9	0.0	
	COLUMN TOTAL	79	107	60	45	52	18	18	22	37	438
		18.0	24.4	13.7	10.3	11.9	4.1	4.1	5.0	8.4	100.0

NUMBER OF MISSING OBSERVATIONS = 1

TABLE A-10. BOILER CAPACITY CATEGORY BY YEAR SOLD FOR EACH PRIMARY OR ALTERNATE FUEL (Continued) - - WASTE HEAT

```
                              YEAR  SOLD
                       COUNT  I                WASTEHEAT
                     ROW PCT  I                                                  ROW
                     COL PCT  I                                                 TOTAL
BOILER CAPACITY      TOT PCT  I      69  I      71  I      72  I      73  I
  CATEGORY          --------I--------I--------I--------I--------I
                           2  I       0  I      30  I      14  I       8  I      52
     16-100KPH                I     0.0  I    57.7  I    26.9  I    15.4  I    62.7
                              I     0.0  I    75.0  I    56.0  I    57.1  I
                              I     0.0  I    36.1  I    16.9  I     9.6  I
                            -I--------I--------I--------I--------I
                           3  I       4  I       8  I       0  I       6  I      18
     100-250KPH               I    22.2  I    44.4  I     0.0  I    33.3  I    21.7
                              I   100.0  I    20.0  I     0.0  I    42.9  I
                              I     4.8  I     9.6  I     0.0  I     7.2  I
                            -I--------I--------I--------I--------I
                           4  I       0  I       2  I      11  I       0  I      13
     250-500KPH               I     0.0  I    15.4  I    84.6  I     0.0  I    15.7
                              I     0.0  I     5.0  I    44.0  I     0.0  I
                              I     0.0  I     2.4  I    13.3  I     0.0  I
                            -I--------I--------I--------I--------I
                      COLUMN          4         40         25         14        83
                       TOTAL        4.8       48.2       30.1       16.9     100.0

     NUMBER OF MISSING OBSERVATIONS =       1
```

TABLE A-11. ERECTION METHOD BY CAPACITY CATEGORY FOR WATERTUBE BOILERS

```
                           CATEG
                   COUNT  I
                 ROW PCT  I0-16KPH 16-100KP 100-250K 250-500K 500+KPH      ROW
                 COL PCT  I         H        PH       PH                  TOTAL
  ERECTION       TOT PCT  I    1  I     2  I     3  I     4  I     8  I
   METHOD        ---------I-------I--------I--------I--------I--------I
                        1 I   469 I  5631  I  1066  I    53  I     1  I  7220
  PACKAGED                I   6.5 I  78.0  I  14.8  I   0.7  I   0.0  I  78.3
                          I  89.2 I  88.8  I  68.9  I  17.5  I   0.2  I
                          I   5.1 I  61.1  I  11.6  I   0.6  I   0.0  I
                         -I-------I--------I--------I--------I--------I
  FIELD ASSEMBLED       2 I    57 I   709  I   481  I   250  I   505  I  2002
                          I   2.8 I  35.4  I  24.0  I  12.5  I  25.2  I  21.7
                          I  10.8 I  11.2  I  31.1  I  82.5  I  99.8  I
                          I   0.6 I   7.7  I   5.2  I   2.7  I   5.5  I
                         -I-------I--------I--------I--------I--------I
                  COLUMN      526     6340     1547      303      506     9222
                   TOTAL      5.7     68.7     16.8      3.3      5.5    100.0

NUMBER OF MISSING OBSERVATIONS =     80
```

TABLE A-12. FIRING METHOD BY CAPACTIY CATEGORY FOR SOLID FUELS -- BITUMINOUS COAL

FIRING	CATEG COUNT ROW PCT COL PCT	0.00	10-16KPH 1.00	16-100KPH 2.00	100-250KPH 3.00	250-500KPH 4.00	500+KPH 8.00	ROW TOTAL
UNSPECIFIED	-0.	3 4.4 75.0	2 2.9 20.0	36 52.9 16.7	15 22.1 14.7	2 2.9 6.9	10 14.7 4.3	68 11.4
PULVERIZED COAL	1.	0 0.0 0.0	0 0.0 0.0	1 0.4 0.5	16 6.7 15.7	21 8.8 72.4	202 84.2 86.0	240 40.3
SPREADER STOKER	2.	0 0.0 0.0	2 1.4 20.0	88 59.5 40.7	56 37.8 54.9	2 1.4 6.9	0 0.0 0.0	148 24.8
UNDERFEED STOKER	3.	1 3.0 25.0	6 18.2 60.0	26 78.8 12.0	0 0.0 0.0	0 0.0 0.0	0 0.0 0.0	33 5.5
OVERFEED STOKER	4.	0 0.0 0.0	0 0.0 0.0	43 89.6 19.9	5 10.4 4.9	0 0.0 0.0	0 0.0 0.0	48 8.1
OTHER SOLID	5.	0 0.0 0.0	0 0.0 0.0	22 39.3 10.2	10 17.9 9.8	3 5.4 10.3	21 37.5 8.9	56 9.4
NON-SOLID FUEL	9.	0 0.0 0.0	0 0.0 0.0	0 0.0 0.0	0 0.0 0.0	1 33.3 3.4	2 66.7 0.9	3 0.5
COLUMN TOTAL		4 0.7	10 1.7	216 36.2	102 17.1	29 4.9	235 39.4	596 100.0

TABLE A-12. FIRING METHOD BY CAPACITY CATEGORY FOR SOLID FUELS (Continued) -- WOOD WASTE

	COUNT ROW PCT COL PCT	BOILER CAPACITY CATEGORY						
			10-16KPH	16-100KPH	100-250KPH	250-500KPH	500+KPH	ROW TOTAL
FIRING METHOD		0.00	1.00	2.00	3.00	4.00	8.00	
-0. UNSPECIFIED	COUNT	1	1	8	2	3	0	15
	ROW PCT	6.7	6.7	53.3	13.3	20.0	0.0	10.1
	COL PCT	100.0	33.3	7.2	8.0	100.0	0.0	
1. PULVERIZED COAL	COUNT	0	0	0	0	0	1	1
	ROW PCT	0.0	0.0	0.0	0.0	0.0	100.0	0.7
	COL PCT	0.0	0.0	0.0	0.0	0.0	16.7	
2. SPREADER STOKER	COUNT	0	1	42	19	0	3	65
	ROW PCT	0.0	1.5	64.6	29.2	0.0	4.6	43.6
	COL PCT	0.0	33.3	37.8	76.0	0.0	50.0	
3. UNDERFEED STOKER	COUNT	0	0	2	0	0	0	2
	ROW PCT	0.0	0.0	100.0	0.0	0.0	0.0	1.3
	COL PCT	0.0	0.0	1.8	0.0	0.0	0.0	
4. OVERFEED STOKER	COUNT	0	0	26	4	0	0	30
	ROW PCT	0.0	0.0	86.7	13.3	0.0	0.0	20.1
	COL PCT	0.0	0.0	23.4	16.0	0.0	0.0	
5. OTHER SOLID	COUNT	0	1	25	0	0	2	28
	ROW PCT	0.0	3.6	89.3	0.0	0.0	7.1	18.8
	COL PCT	0.0	33.3	22.5	0.0	0.0	33.3	
9. NON-SOLID FUEL	COUNT	0	0	8	0	0	0	8
	ROW PCT	0.0	0.0	100.0	0.0	0.0	0.0	5.4
	COL PCT	0.0	0.0	7.2	0.0	0.0	0.0	
COLUMN TOTAL		1 0.7	3 2.0	111 74.5	25 16.8	3 2.0	6 4.0	149 100.0

TABLE A-12. FIRING METHOD BY CAPACITY CATEGORY FOR SOLID FUELS (Continued) -- BAGASSE

COUNT ROW PCT COL PCT	BOILER CAPACITY CATEGORY 16-100KPH 2.00	 100-250KPH 3.00	 250-500KPH 4.00	 500+KPH 8.00	 ROW TOTAL
FIRING METHOD					
-0. UNSPECIFIED	3 75.0 13.0	0 0.0 0.0	0 0.0 0.0	1 25.0 100.0	4 9.1
2. SPREADER STOKER	3 15.8 13.0	15 78.9 78.9	1 5.3 100.0	0 0.0 0.0	19 43.2
3. UNDERFEED STOKER	1 100.0 4.3	0 0.0 0.0	0 0.0 0.0	0 0.0 0.0	1 2.3
4. OVERFEED STOKER	1 100.0 4.3	0 0.0 0.0	0 0.0 0.0	0 0.0 0.0	1 2.3
5. OTHER SOLID	14 82.4 60.9	3 17.6 15.8	0 0.0 0.0	0 0.0 0.0	17 38.6
9. NON-SOLID FUEL	1 50.0 4.3	1 50.0 5.3	0 0.0 0.0	0 0.0 0.0	2 4.5
COLUMN TOTAL	23 52.3	19 43.2	1 2.3	1 2.3	44 100.0

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TABLE A-13. PRIMARY FUEL BY BOILER CAPACITY CATEGORY FOR WATERTUBE BOILERS

```
             COUNT  I
           ROW PCT  I10-16KPH 16-100KP 100-250K 250-500K 500+KPH     ROW
           COL PCT  I         H        PH       PH                   TOTAL
           TOT PCT  I      1  I      2  I      3  I      4  I      8  I
PRIMARY FUEL --------I--------I--------I--------I--------I--------I
                  1  I     10  I    215  I     97  I     28  I    224  I    574
  BITUMINOUS COAL    I    1.7  I   37.5  I   16.9  I    4.9  I   39.0  I    6.4
                     I    1.9  I    3.5  I    6.5  I    9.4  I   46.7  I
                     I    0.1  I    2.4  I    1.1  I    0.3  I    2.5  I
                    -I--------I--------I--------I--------I--------I
                  2  I    140  I   1689  I    472  I     74  I    119  I   2494
  OIL                I    5.6  I   67.7  I   18.9  I    3.0  I    4.8  I   27.9
                     I   27.1  I   27.5  I   31.8  I   24.9  I   24.8  I
                     I    1.6  I   18.9  I    5.3  I    0.8  I    1.3  I
                    -I--------I--------I--------I--------I--------I
                  3  I    345  I   3911  I    723  I     72  I    102  I   5153
  NATURAL GAS        I    6.7  I   75.9  I   14.0  I    1.4  I    2.0  I   57.7
                     I   66.9  I   63.6  I   48.7  I   24.2  I   21.3  I
                     I    3.9  I   43.8  I    8.1  I    0.8  I    1.1  I
                    -I--------I--------I--------I--------I--------I
                  4  I      3  I     99  I     25  I      3  I      6  I    136
  WOODBARK           I    2.2  I   72.8  I   18.4  I    2.2  I    4.4  I    1.5
                     I    0.6  I    1.6  I    1.7  I    1.0  I    1.3  I
                     I    0.0  I    1.1  I    0.3  I    0.0  I    0.1  I
                    -I--------I--------I--------I--------I--------I
                  5  I      0  I     23  I     17  I      1  I      1  I     42
  BAGASSE            I    0.0  I   54.8  I   40.5  I    2.4  I    2.4  I    0.5
                     I    0.0  I    0.4  I    1.1  I    0.3  I    0.2  I
                     I    0.0  I    0.3  I    0.2  I    0.0  I    0.0  I
                    -I--------I--------I--------I--------I--------I
                  6  I      0  I     12  I     32  I     51  I     14  I    109
  BLACK LIQUOR       I    0.0  I   11.0  I   29.4  I   46.8  I   12.8  I    1.2
                     I    0.0  I    0.2  I    2.2  I   17.2  I    2.9  I
                     I    0.0  I    0.1  I    0.4  I    0.6  I    0.2  I
                    -I--------I--------I--------I--------I--------I
                  7  I     18  I    142  I     97  I     53  I     11  I    321
  OTHER FUELS        I    5.6  I   44.2  I   30.2  I   16.5  I    3.4  I    3.6
                     I    3.5  I    2.3  I    6.5  I   17.8  I    2.3  I
                     I    0.2  I    1.6  I    1.1  I    0.6  I    0.1  I
                    -I--------I--------I--------I--------I--------I
             COLUMN        516     6147     1485      297      480      8925
              TOTAL        5.8     68.9     16.6      3.3      5.4     100.0
(CONTINUED)
```

TABLE A-13. PRIMARY FUEL BY BOILER CAPACITY CATEGORY FOR WATERTUBE BOILERS (Continued)

```
             COUNT   I
            ROW PCT  I10-16KPH 16-100KP 100-250K 250-510K 500+KPH     ROW
            COL PCT  I         H        PH       PH                  TOTAL
            TOT PCT  I      1 I      2 I      3 I      4 I      5 I
PRIMARY FUEL --------I--------I--------I--------I--------I--------I
                   8 I      0 I     51 I     14 I     13 I      0 I     78
  WASTEHEAT          I    0.0 I   65.4 I   17.9 I   16.7 I    0.0 I    0.9
                     I    0.0 I    0.8 I    0.9 I    4.4 I    0.0 I
                     I    0.0 I    0.6 I    0.2 I    0.1 I    0.0 I
                    -I--------I--------I--------I--------I--------I
                   9 I      0 I      5 I      8 I      2 I      0 I     15
  WITH AUX. FIRING   I    0.0 I   33.3 I   53.3 I   13.3 I    0.0 I    0.2
                     I    0.0 I    0.1 I    0.5 I    0.7 I    0.0 I
                     I    0.0 I    0.1 I    0.1 I    0.0 I    0.0 I
                    -I--------I--------I--------I--------I--------I
                  10 I      0 I      0 I      0 I      0 I      3 I      3
  LIGNITE            I    0.0 I    0.0 I    0.0 I    0.0 I  100.0 I    0.0
                     I    0.0 I    0.0 I    0.0 I    0.0 I    0.6 I
                     I    0.0 I    0.0 I    0.0 I    0.0 I    0.0 I
                    -I--------I--------I--------I--------I--------I
             COLUMN       516     6147     1495      297      480     8925
              TOTAL       5.8     63.9     16.6      3.3      5.4    100.0

NUMBER OF MISSING OBSERVATIONS =    98
```

TABLE A-14. ALTERNATE FUEL BY CAPACITY CATEGORY FOR WATERTUBE BOILERS

```
                       CATEG
             COUNT   I
             ROW PCT I10-16KPH 16-100KP 100-250K 250-500K 500+KPH      ROW
             COL PCT I          H        PH       PH                  TOTAL
             TOT PCT I     1.00I     2.00I     3.00I     4.00I     8.00I
 ALTFUEL     --------I--------I---------I---------I---------I---------I
           X         I    211  I   2247  I    715  I    104  I    308  I   3585
   NONE              I    5.9  I   62.7  I   19.9  I    2.9  I    8.6  I   40.1
                     I   48.9  I   36.5  I   48.1  I   34.9  I   63.0  I
                     I    2.4  I   25.1  I    8.0  I    1.2  I    3.4  I
                    -I--------I---------I---------I---------I---------I
           0         I      0  I     26  I      3  I      5  I      3  I     37
                     I    0.0  I   70.3  I    8.1  I   13.5  I    8.1  I    0.4
                     I    0.0  I    0.4  I    0.2  I    1.7  I    0.6  I
                     I    0.0  I    0.3  I    0.0  I    0.1  I    0.0  I
                    -I--------I---------I---------I---------I---------I
           1         I      0  I     10  I      4  I      3  I      5  I     22
   BITUMINOUS COAL   I    0.0  I   45.5  I   18.2  I   13.6  I   22.7  I    0.2
                     I    0.0  I    0.2  I    0.3  I    1.0  I    1.0  I
                     I    0.0  I    0.1  I    0.0  I    0.0  I    0.1  I
                    -I--------I---------I---------I---------I---------I
           2         I    282  I   3283  I    523  I     83  I    112  I   4283
   OIL               I    6.6  I   76.7  I   12.2  I    1.9  I    2.6  I   47.9
                     I   54.7  I   53.3  I   35.2  I   27.9  I   22.9  I
                     I    3.2  I   36.7  I    5.8  I    0.9  I    1.3  I
                    -I--------I---------I---------I---------I---------I
           3         I     22  I    530  I    175  I     80  I     51  I    858
   NATURAL GAS       I    2.6  I   61.8  I   20.4  I    9.3  I    5.9  I    9.6
                     I    4.3  I    8.6  I   11.8  I   26.8  I   10.4  I
                     I    0.2  I    5.9  I    2.0  I    0.9  I    0.6  I
                    -I--------I---------I---------I---------I---------I
           4         I      0  I     11  I      3  I      1  I      1  I     16
   WOOD BARK         I    0.0  I   68.8  I   18.7  I    6.3  I    6.3  I    0.2
                     I    0.0  I    0.2  I    0.2  I    0.3  I    0.2  I
                     I    0.0  I    0.1  I    0.0  I    0.0  I    0.0  I
                    -I--------I---------I---------I---------I---------I
           6         I      0  I      1  I      0  I      0  I      0  I      1
   BLACK LIQUOR      I    0.0  I  100.0  I    0.0  I    0.0  I    0.0  I    0.0
                     I    0.0  I    0.0  I    0.0  I    0.0  I    0.0  I
                     I    0.0  I    0.0  I    0.0  I    0.0  I    0.0  I
                    -I--------I---------I---------I---------I---------I
              COLUMN      516      6159      1486       298       489      8948
               TOTAL      5.8      68.8      16.6       3.3       5.5     100.0
 (CONTINUED)
```

TABLE A-14. ALTERNATE FUEL BY CAPACITY CATEGORY FOR WATERTUBE BOILERS (Continued)

```
                  CATEG
        COUNT   I
      ROW PCT   I10-16KPH 16-100KP 100-250K 250-500K 500+KPH     ROW
      COL PCT   I          H       PH       PH                  TOTAL
      TOT PCT   I    1.00I    2.00I    3.00I    4.00I    8.00I
ALTFUEL         --------I--------I--------I--------I--------I
         7      I     1  I    51  I    60  I    21  I     9  I    142
   OTHER FUELS  I   0.7  I  35.9  I  42.3  I  14.8  I   6.3  I    1.6
                I   0.2  I   0.8  I   4.0  I   7.0  I   1.8  I
                I   0.0  I   0.6  I   0.7  I   0.2  I   0.1  I
               -I--------I--------I--------I--------I--------I
         8      I     0  I     0  I     2  I     0  I     0  I      2
   WASTEHEAT    I   0.0  I   0.0  I 100.0  I   0.0  I   0.0  I    0.0
                I   0.0  I   0.0  I   0.1  I   0.0  I   0.0  I
                I   0.0  I   0.0  I   0.0  I   0.0  I   0.0  I
               -I--------I--------I--------I--------I--------I
         9      I     0  I     0  I     1  I     1  I     0  I      2
  WITH AUX. FIRING I 0.0 I   0.0  I  50.0  I  50.0  I   0.0  I    0.0
                I   0.0  I   0.0  I   0.1  I   0.3  I   0.0  I
                I   0.0  I   0.0  I   0.0  I   0.0  I   0.0  I
               -I--------I--------I--------I--------I--------I
        COLUMN      516      6159     1486      298      489     8948
         TOTAL      5.8      68.8     16.6      3.3      5.5    100.0

NUMBER OF MISSING OBSERVATIONS =       75
```

TABLE A-15. PRIMARY FUEL BY CAPACITY CATEGORY FOR EXPORTED WATERTUBE BOILERS

PRIMARY FUEL	COUNT ROW PCT COL PCT TOT PCT	10-16KPH 1	16-100KPH 2	100-250KPH 3	250-500KPH 4	500+KPH 8	ROW TOTAL
BITUMINOUS COAL	1	0	0	0	0	2	2
		0.0	0.0	0.0	0.0	100.0	0.9
		0.0	0.0	0.0	0.0	12.5	
		0.0	0.0	0.0	0.0	0.9	
OIL	2	2	67	37	9	8	123
		1.6	54.5	30.1	7.3	6.5	55.2
		100.0	74.4	47.4	24.3	50.0	
		0.9	30.0	16.6	4.0	3.6	
NATURAL GAS	3	0	16	10	27	5	58
		0.0	27.6	17.2	46.6	8.6	26.0
		0.0	17.8	12.8	73.0	31.3	
		0.0	7.2	4.5	12.1	2.2	
WOODBARK	4	0	0	1	0	0	1
		0.0	0.0	100.0	0.0	0.0	0.4
		0.0	0.0	1.3	0.0	0.0	
		0.0	0.0	0.4	0.0	0.0	
BLACK LIQUOR	6	0	1	0	0	0	1
		0.0	100.0	0.0	0.0	0.0	0.4
		0.0	1.1	0.0	0.0	0.0	
		0.0	0.4	0.0	0.0	0.0	
OTHER FUELS	7	0	6	29	0	1	36
		0.0	16.7	80.6	0.0	2.8	16.1
		0.0	6.7	37.2	0.0	6.3	
		0.0	2.7	13.0	0.0	0.4	
WITH AUX. FIRING	9	0	0	1	1	0	2
		0.0	0.0	50.0	50.0	0.0	0.9
		0.0	0.0	1.3	2.7	0.0	
		0.0	0.0	0.4	0.4	0.0	
COLUMN TOTAL		2	90	78	37	16	223
		0.9	40.4	35.0	16.6	7.2	100.0

TABLE A-16. PRIMARY FUEL BY YEAR SOLD FOR WATERTUBE BOILERS

YEAR SOLD	COUNT ROW PCT COL PCT TOT PCT	PRIMARY FUEL -0.	BITUMINOUS COAL 1.	OIL 2.	NATURAL GAS 3.	WOODBARK 4.	BAGASSE 5.	BLACK LIQUOR 6.	OTHER FUELS 7.	WASTEHEAT 8.	WITH AUX. FIRING 9.	ROW TOTAL
65.		6	161	316	594	13	2	19	60	0	0	1171
		0.5	13.7	27.0	50.7	1.1	0.2	1.6	5.1	0.0	0.0	12.6
		26.1	27.0	12.0	11.2	8.7	4.5	16.8	18.5	0.0	0.0	
		0.1	1.7	3.4	6.4	0.1	0.0	0.2	0.6	0.0	0.0	
66.		4	130	346	707	4	2	15	64	0	0	1272
		0.3	10.2	27.2	55.6	0.3	0.2	1.2	5.0	0.0	0.0	13.7
		17.4	21.8	13.2	13.3	2.7	4.5	13.3	19.8	0.0	0.0	
		0.0	1.4	3.7	7.6	0.0	0.0	0.2	0.7	0.0	0.0	
67.		0	78	214	598	6	0	4	46	0	0	946
		0.0	8.2	22.6	63.2	0.6	0.0	0.4	4.9	0.0	0.0	10.2
		0.0	13.1	8.1	11.2	4.0	0.0	3.5	14.2	0.0	0.0	
		0.0	0.8	2.3	6.4	0.1	0.0	0.0	0.5	0.0	0.0	
68.		1	38	204	619	11	3	5	35	0	0	916
		0.1	4.1	22.3	67.6	1.2	0.3	0.5	3.8	0.0	0.0	9.8
		4.3	6.4	7.8	11.6	7.4	6.8	4.4	10.8	0.0	0.0	
		0.0	0.4	2.2	6.7	0.1	0.0	0.1	0.4	0.0	0.0	
69.		0	49	230	767	20	6	12	45	2	3	1134
		0.0	4.3	20.3	67.6	1.8	0.5	1.1	4.0	0.2	0.3	12.2
		0.0	8.2	8.8	14.4	13.4	13.6	10.6	13.9	2.4	18.7	
		0.0	0.5	2.5	8.2	0.2	0.1	0.1	0.5	0.0	0.0	
70.		2	38	311	619	7	3	9	13	0	5	1006
		0.2	3.8	30.9	61.4	0.7	0.3	0.9	1.3	0.0	0.5	10.8
		8.7	6.4	11.8	11.6	4.7	6.8	8.0	4.0	0.0	31.3	
		0.0	0.4	3.3	6.6	0.1	0.0	0.1	0.1	0.0	0.1	
71.		7	33	386	535	17	10	16	16	40	5	1065
		0.7	3.1	36.2	50.2	1.6	0.9	1.5	1.5	3.8	0.5	11.4
		30.4	5.5	14.7	10.1	11.4	22.7	14.2	4.9	48.8	31.3	
		0.1	0.4	4.1	5.8	0.2	0.1	0.2	0.2	0.4	0.1	
COLUMN TOTAL		23	596	2628	5322	149	44	113	324	82	16	9302
		0.2	6.4	28.3	57.2	1.6	0.5	1.2	3.5	0.9	0.2	100.0

(CONTINUED)

TABLE A-16. PRIMARY FUEL BY YEAR SOLD FOR WATERTUBE BOILERS (Continued)

```
                         PRIMARY FUEL
             COUNT  I
            ROW PCT ILIGNITE  NON-COMB   ROW
            COL PCT I         US REMOV  TOTAL
            TOT PCT I    10.I     11.I
YEAR SOLD   --------I--------I--------I
                65. I      0 I      0 I  1171
                    I    0.0 I    0.0 I  12.6
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                66. I      0 I      0 I  1272
                    I    0.0 I    0.0 I  13.7
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                67. I      0 I      0 I   946
                    I    0.0 I    0.0 I  10.2
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                68. I      0 I      0 I   916
                    I    0.0 I    0.0 I   9.8
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                69. I      0 I      0 I  1134
                    I    0.0 I    0.0 I  12.2
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                70. I      0 I      0 I  1006
                    I    0.0 I    0.0 I  10.8
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
                71. I      0 I      0 I  1065
                    I    0.0 I    0.0 I  11.4
                    I    0.0 I    0.0 I
                    I    0.0 I    0.0 I
                   -I--------I--------I
             COLUMN        4        1    9302
              TOTAL      0.0      0.0   100.0
(CONTINUED)
```

TABLE A-16. PRIMARY FUEL BY YEAR SOLD FOR WATERTUBE BOILERS (Continued)

```
                    PRIMARY FUEL
              COUNT  I
             ROW PCT I          BITUMINO OIL       NATURAL  WOODBARK BAGASSE  BLACK LI OTHER FU WASTEHEA WITH AUX   ROW
             COL PCT I          US COAL            GAS                        QUOR     ELS      T        , FIRING  TOTAL
YEAR SOLD    TOT PCT I     -9.I      1.I      2.I      3.I      4.I      5.I      6.I      7.I      8.I      9.I
             --------I--------I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                 72. I      3 I     37 I    353 I    548 I     27 I      9 I     18 I     15 I     25 I      2 I   1337
                     I    0.3 I    3.6 I   34.0 I   52.8 I    2.6 I    0.9 I    1.7 I    1.4 I    2.4 I    0.2 I   11.1
                     I   13.0 I    6.2 I   13.4 I   10.3 I   18.1 I   20.5 I   15.9 I    4.6 I   30.5 I   12.5 I
                     I    0.0 I    0.4 I    3.8 I    5.9 I    0.3 I    0.1 I    0.2 I    0.2 I    0.3 I    0.0 I
                    -I--------I--------I--------I--------I--------I--------I--------I--------I--------I--------I
                 73. I      0 I     32 I    268 I    336 I     44 I      9 I     15 I     30 I     15 I      1 I    755
                     I    0.0 I    4.2 I   35.5 I   44.5 I    5.8 I    1.2 I    2.0 I    4.0 I    2.0 I    0.1 I    8.1
                     I    0.0 I    5.4 I   10.2 I    6.3 I   29.5 I   20.5 I   13.3 I    9.3 I   18.3 I    6.3 I
                     I    0.0 I    0.3 I    2.9 I    3.6 I    0.5 I    0.1 I    0.2 I    0.3 I    0.2 I    0.0 I
                    -I--------I--------I--------I--------I--------I--------I--------I--------I--------I--------I
              COLUMN       23      596     2628     5322      149       44      113      324       92       16     9307
               TOTAL      0.2      6.4     28.3     57.2      1.6      0.5      1.2      3.5      0.9      0.2    100.0
(CONTINUED)
```

TABLE A-16. PRIMARY FUEL BY YEAR SOLD FOR WATERTUBE BOILERS (Continued)

```
                           PRIMARY FUEL
               COUNT   I
              ROW PCT ILIGNITE  NON-COMB   ROW
              COL PCT I         US REMOV  TOTAL
              TOT PCT I      10.I      12.I
YEAR SOLD     --------I--------I--------I
                  77.  I       0 I       0 I  1037
                       I    0.0  I    0.0  I  11.1
                       I    0.0  I    0.0  I
                       I    0.0  I    0.0  I
                      -I--------I--------I
                  73.  I       4 I       1 I   755
                       I    0.5  I    0.1  I   8.1
                       I  100.0  I  100.0  I
                       I    0.0  I    0.0  I
                      -I--------I--------I
              COLUMN          4         1    9302
               TOTAL        0.0       0.0   100.0
```

TABLE A-17. PRIMARY FUEL BY ALTERNATE FUEL FOR WATERTUBE BOILERS

PRIMARY FUEL	ALTERNATE FUEL COUNT ROW PCT COL PCT TOT PCT	NONE X	0	BITUMINOUS COAL 1	OIL 2	NATURAL GAS 3	WOOD BARK 4	BLACK LIQUOR 6	OTHER FUELS 7	WASTEHEAT 8	WITH AUX. FIRING 9	ROW TOTAL
	0.	8	0	0	0	0	0	0	0	0	0	8
		100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
		0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	1.	454	1	2	45	55	8	0	12	0	1	578
BITUMINOUS COAL		78.5	0.2	0.3	7.8	9.5	1.4	0.0	2.1	0.0	0.2	6.4
		12.6	2.7	9.1	1.0	6.4	50.0	0.0	8.4	0.0	50.0	
		5.0	0.0	0.0	0.5	0.6	0.1	0.0	0.1	0.0	0.0	
	2.	1756	27	10	22	673	3	0	30	0	1	2522
OIL		69.6	1.1	0.4	0.9	26.7	0.1	0.0	1.2	0.0	0.0	28.0
		48.7	73.0	45.5	0.5	77.7	18.7	0.0	21.0	0.0	50.0	
		19.5	0.3	0.1	0.2	7.5	0.0	0.0	0.3	0.0	0.0	
	3.	1028	9	3	4075	2	5	0	70	2	0	5194
NATURAL GAS		19.8	0.2	0.1	78.5	0.0	0.1	0.0	1.3	0.0	0.0	57.7
		28.5	24.3	13.6	94.5	0.2	31.3	0.0	49.0	100.0	0.0	
		11.4	0.1	0.0	45.2	0.0	0.1	0.0	0.8	0.0	0.0	
	4.	73	0	3	29	32	0	0	0	0	0	137
WOODBARK		53.3	0.0	2.2	21.2	23.4	0.0	0.0	0.0	0.0	0.0	1.5
		2.0	0.0	13.6	0.7	3.7	0.0	0.0	0.0	0.0	0.0	
		0.8	0.0	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	
	5.	16	0	0	17	8	0	1	0	0	0	42
BAGASSE		38.1	0.0	0.0	40.5	19.0	0.0	2.4	0.0	0.0	0.0	0.5
		0.4	0.0	0.0	0.4	0.9	0.0	100.0	0.0	0.0	0.0	
		0.2	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	
	6.	23	0	0	56	30	0	0	0	0	0	109
BLACK LIQUOR		21.1	0.0	0.0	51.4	27.5	0.0	0.0	0.0	0.0	0.0	1.2
		0.6	0.0	0.0	1.3	3.5	0.0	0.0	0.0	0.0	0.0	
		0.3	0.0	0.0	0.6	0.3	0.0	0.0	0.0	0.0	0.0	
	COLUMN TOTAL	3607	37	22	4312	866	16	1	143	2	2	9008
		40.0	0.4	0.2	47.9	9.6	0.2	0.0	1.6	0.0	0.0	100.0

(CONTINUED)

TABLE A-17. PRIMARY FUEL BY ALTERNATE FUEL FOR WATERTUBE BOILERS (Continued)

PRIMARY FUEL	ALTERNATE FUEL COUNT ROW PCT COL PCT TOT PCT	NONE X	0	BITUMINOUS COAL 1	OIL 2	NATURAL GAS 3	WOOD BARK 4	BLACK LIQUOR 6	OTHER FUELS 7	WASTEHEAT 8	WITH AUX. FIRING 9	ROW TOTAL
7.		168	0	4	63	55	0	0	31	0	0	321
OTHER FUELS		52.3	0.0	1.2	19.6	17.1	0.0	0.0	9.7	0.0	0.0	3.6
		4.7	0.0	18.2	1.5	6.4	0.0	0.0	21.7	0.0	0.0	
		1.9	0.0	0.0	0.7	0.6	0.0	0.0	0.3	0.0	0.0	
8.		74	0	0	0	5	0	0	0	0	0	79
WASTEHEAT		93.7	0.0	0.0	0.0	6.3	0.0	0.0	0.0	0.0	0.0	0.9
		2.1	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	
		0.8	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	
9.		4	0	0	5	6	0	0	0	0	0	15
WITH AUX. FIRING		26.7	0.0	0.0	33.3	40.0	0.0	0.0	0.0	0.0	0.0	0.2
		0.1	0.0	0.0	0.1	0.7	0.0	0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	
10.		3	0	0	0	0	0	0	0	0	0	3
LIGNITE		100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	COLUMN TOTAL	3607 40.0	37 0.4	22 0.2	4312 47.9	866 9.6	18 0.2	1 0.0	143 1.6	2 0.0	2 0.0	9008 100.0

NUMBER OF MISSING OBSERVATIONS = 15

TABLE A-18. ERECTION METHOD BY PRIMARY FUEL FOR WATERTUBE BOILERS

ERECTION METHOD	COUNT / ROW PCT / COL PCT / TOT PCT	PRIMARY FUEL BITUMINO US COAL 1	OIL 2	NATURAL GAS 3	WOODBARK 4	BAGASSE 5	BLACK LI QUOR 6	OTHER FU ELS 7	WASTEHEA T 8	WITH AUX . FIRING 9	LIGNITE 10	NON-COMB US REMOV 12	ROW TOTAL
1	COUNT	36	2086	4905	32	0	4	148	53	9	0	0	7273
PACKAGED	ROW PCT	9.5	28.7	67.4	0.4	0.0	0.1	2.0	0.7	0.1	0.0	0.0	78.4
	COL PCT	6.0	79.4	92.2	21.5	0.0	3.5	45.7	64.6	56.3	0.0	0.0	
	TOT PCT	0.4	22.5	52.9	0.3	0.0	0.0	1.6	0.6	0.1	0.0	0.0	
2	COUNT	560	542	416	117	44	109	176	29	7	4	1	2005
FIELD ASSEMBLED	ROW PCT	27.9	27.0	20.7	5.8	2.2	5.4	8.8	1.4	0.3	0.2	0.0	21.6
	COL PCT	94.0	20.6	7.8	78.5	100.0	96.5	54.3	35.4	43.8	100.0	100.0	
	TOT PCT	6.0	5.8	4.5	1.3	0.5	1.2	1.9	0.3	0.1	0.0	0.0	
COLUMN TOTAL		596	2628	5321	149	44	113	324	62	16	4	1	9278
		6.4	28.3	57.4	1.6	0.5	1.2	3.5	0.9	0.2	0.0	0.0	100.0

NUMBER OF MISSING OBSERVATIONS = 24

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TABLE A-19. ERECTION METHOD BY YEAR FOR WATERTUBE BOILERS

```
                  YEAR SOLD
           COUNT I
         ROW PCT I                                                                                         ROW
         COL PCT I                                                                                         TOTAL
         TOT PCT I    65   I    66   I    67   I    68   I    69   I    70   I    71   I    72   I    73   I
ERECTION METHOD  --------I---------I---------I---------I---------I---------I---------I---------I---------I
               1 I   794   I   946   I   718   I   787   I   932   I   806   I   866   I   831   I   605   I   7285
  PACKAGED       I  10.9   I  13.0   I   9.9   I  10.8   I  12.8   I  11.1   I  11.9   I  11.4   I   8.3   I   78.3
                 I  67.8   I  74.4   I  75.9   I  85.9   I  82.2   I  80.1   I  81.4   I  80.2   I  80.1   I
                 I   8.5   I  10.2   I   7.7   I   8.5   I  10.0   I   8.7   I   9.3   I   8.9   I   6.5   I
                -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
               2 I   377   I   326   I   228   I   129   I   202   I   200   I   198   I   205   I   150   I   2015
                 I  18.7   I  16.2   I  11.3   I   6.4   I  10.0   I   9.9   I   9.8   I  10.2   I   7.4   I   21.7
  FIELD ASSEMBLED I  32.2  I  25.6   I  24.1   I  14.1   I  17.8   I  19.9   I  18.6   I  19.8   I  19.9   I
                 I   4.1   I   3.5   I   2.5   I   1.4   I   2.2   I   2.2   I   2.1   I   2.2   I   1.6   I
                -I---------I---------I---------I---------I---------I---------I---------I---------I---------I
          COLUMN     1171      1272       946       916      1134      1006      1064      1036       755      9300
           TOTAL     12.6      13.7      10.2       9.8      12.2      10.8      11.4      11.1       8.1     100.0

 NUMBER OF MISSING OBSERVATIONS =        2
```

TABLE A-20. FIRING METHOD FOR COAL BY YEAR FOR EACH WATERTUBE CAPACITY CATEGORY -- 10-16 KPH

```
                     YEAR
            COUNT  I
           ROW PCT I                                              ROW
           COL PCT I                                              TOTAL
           TOT PCT I     55.I      66.I      67.I      68.I
FIRING     --------I---------I---------I---------I---------I
              -0.  I      0  I      0  I      2  I      0  I      2
                   I    0.0  I    0.0  I  100.0  I    0.0  I   20.0
                   I    0.0  I    0.0  I   50.0  I    0.0  I
                   I    0.0  I    0.0  I   20.0  I    0.0  I
                  -I---------I---------I---------I---------I
               2.  I      0  I      2  I      0  I      0  I      2
   SPREADER STOKER I    0.0  I  100.0  I    0.0  I    0.0  I   20.0
                   I    0.0  I  100.0  I    0.0  I    0.0  I
                   I    0.0  I   20.0  I    0.0  I    0.0  I
                  -I---------I---------I---------I---------I
               3.  I      3  I      0  I      2  I      1  I      6
  UNDERFEED STOKER I   50.0  I    0.0  I   33.3  I   16.7  I   60.0
                   I  100.0  I    0.0  I   50.0  I  100.0  I
                   I   30.0  I    0.0  I   20.0  I   10.0  I
                  -I---------I---------I---------I---------I
            COLUMN        3         2         4         1        10
             TOTAL     30.0      20.0      40.0      10.0     100.0
```

TABLE A-20. FIRING METHOD FOR COAL BY YEAR FOR EACH WATERTUBE CAPACITY CATEGORY (Continued) -- 17-100 KPH

FIRING	COUNT ROW PCT COL PCT TOT PCT	YEAR 65.	66.	67.	68.	69.	70.	71.	72.	73.	ROW TOTAL
-0.		17 40.5 22.4 7.5	11 26.2 18.0 4.9	9 21.4 28.1 4.0	2 4.8 8.0 0.9	3 7.1 17.6 1.3	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	42 18.6
1. PULVERIZED COAL		0 0.0 0.0 0.0	1 100.0 1.6 0.4	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 0.4
2. SPREADER STOKER		32 35.6 42.1 14.2	26 28.9 42.6 11.5	14 15.6 43.8 6.2	5 5.6 20.0 2.2	7 7.8 41.2 3.1	4 4.4 44.4 1.8	0 0.0 0.0 0.0	1 1.1 100.0 0.4	1 1.1 33.3 0.4	90 39.8
3. UNDERFEED STOKER		8 28.6 10.5 3.5	12 42.9 19.7 5.3	1 3.6 3.1 0.4	3 10.7 12.0 1.3	1 3.6 5.9 0.4	0 0.0 0.0 0.0	2 7.1 100.0 0.9	0 0.0 0.0 0.0	1 3.6 33.3 0.4	28 12.4
4. OVERFEED STOKER		18 41.9 23.7 8.0	7 16.3 11.5 3.1	1 2.3 3.1 0.4	5 11.6 20.0 2.2	6 14.0 35.3 2.7	5 11.6 55.6 2.2	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 2.3 33.3 0.4	43 19.0
5. OTHER SOLID		1 4.5 1.3 0.4	4 18.2 6.6 1.8	7 31.8 21.9 3.1	10 45.5 40.0 4.4	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	22 9.7
COLUMN TOTAL		76 33.6	61 27.0	32 14.2	25 11.1	17 7.5	9 4.0	2 0.9	1 0.4	3 1.3	226 100.0

TABLE A-20. FIRING METHOD FOR COAL BY YEAR FOR EACH WATERTUBE CAPACITY CATEGORY (Continued) -- 101-250 KPH

FIRING	COUNT ROW PCT COL PCT TOT PCT	YEAR 65.	66.	67.	68.	69.	70.	71.	72.	73.	ROW TOTAL
-0.		2 11.8 8.0 1.9	8 47.1 29.6 7.5	3 17.6 30.0 2.8	1 5.9 7.1 0.9	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	3 17.6 37.5 2.8	0 0.0 0.0 0.0	17 16.0
1. PULVERIZED COAL		8 47.1 32.0 7.5	3 17.6 11.1 2.8	2 11.8 20.0 1.9	1 5.9 7.1 0.9	0 0.0 0.0 0.0	0 0.0 0.0 0.0	2 11.8 25.0 1.9	1 5.9 12.5 0.9	0 0.0 0.0 0.0	17 16.0
2. SPREADER STOKER		15 26.3 60.0 14.2	11 19.3 40.7 10.4	4 7.0 40.0 3.8	6 10.5 42.9 5.7	4 7.0 100.0 3.8	4 7.0 80.0 3.8	4 7.0 50.0 3.8	4 7.0 50.0 3.8	5 8.8 100.0 4.7	57 53.8
4. OVERFEED STOKER		0 0.0 0.0 0.0	2 40.0 7.4 1.9	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 20.0 20.0 0.9	2 40.0 25.0 1.9	0 0.0 0.0 0.0	0 0.0 0.0 0.0	5 4.7
5. OTHER SOLID		0 0.0 0.0 0.0	3 30.0 11.1 2.8	1 10.0 10.0 0.9	6 60.0 42.9 5.7	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	10 9.4
COLUMN TOTAL		25 23.6	27 25.5	10 9.4	14 13.2	4 3.8	5 4.7	8 7.5	8 7.5	5 4.7	106 100.0

TABLE A-20. FIRING METHOD FOR COAL BY YEAR FOR EACH WATERTUBE CAPACITY CATEGORY (Continued) -- 251-500 KPH

```
                    YEAR
            COUNT I
          ROW PCT I                                                                                ROW
          COL PCT I                                                                                TOTAL
          TOT PCT I      65.I      66.I      67.I      69.I      70.I      71.I      72.I      73.I
FIRING    --------I---------I---------I---------I---------I---------I---------I---------I---------I
              -0. I       1 I       2 I       0 I       0 I       0 I       0 I       1 I       0 I       4
                  I    25.0 I    50.0 I     0.0 I     0.0 I     0.0 I     0.0 I    25.0 I     0.0 I    12.9
                  I     6.7 I    33.3 I     0.0 I     0.0 I     0.0 I     0.0 I    50.0 I     0.0 I
                  I     3.2 I     6.5 I     0.0 I     0.0 I     0.0 I     0.0 I     3.2 I     0.0 I
                 -I---------I---------I---------I---------I---------I---------I---------I---------I
               1. I      12 I       3 I       0 I       2 I       1 I       1 I       1 I       1 I      21
  PULVERIZED COAL I    57.1 I    14.3 I     0.0 I     9.5 I     4.8 I     4.8 I     4.8 I     4.8 I    67.7
                  I    80.0 I    50.0 I     0.0 I   100.0 I    33.3 I   100.0 I    50.0 I   100.0 I
                  I    38.7 I     9.7 I     0.0 I     6.5 I     3.2 I     3.2 I     3.2 I     3.2 I
                 -I---------I---------I---------I---------I---------I---------I---------I---------I
               2. I       1 I       0 I       0 I       0 I       1 I       0 I       0 I       0 I       2
  SPREADER STOKER I    50.0 I     0.0 I     0.0 I     0.0 I    50.0 I     0.0 I     0.0 I     0.0 I     6.5
                  I     6.7 I     0.0 I     0.0 I     0.0 I    33.3 I     0.0 I     0.0 I     0.0 I
                  I     3.2 I     0.0 I     0.0 I     0.0 I     3.2 I     0.0 I     0.0 I     0.0 I
                 -I---------I---------I---------I---------I---------I---------I---------I---------I
               5. I       1 I       1 I       1 I       0 I       0 I       0 I       0 I       0 I       3
  OTHER SOLID     I    33.3 I    33.3 I    33.3 I     0.0 I     0.0 I     0.0 I     0.0 I     0.0 I     9.7
                  I     6.7 I    16.7 I   100.0 I     0.0 I     0.0 I     0.0 I     0.0 I     0.0 I
                  I     3.2 I     3.2 I     3.2 I     0.0 I     0.0 I     0.0 I     0.0 I     0.0 I
                 -I---------I---------I---------I---------I---------I---------I---------I---------I
               9. I       0 I       0 I       0 I       0 I       1 I       0 I       0 I       0 I       1
  NON-SOLID FUEL  I     0.0 I     0.0 I     0.0 I     0.0 I   100.0 I     0.0 I     0.0 I     0.0 I     3.2
                  I     0.0 I     0.0 I     0.0 I     0.0 I    33.3 I     0.0 I     0.0 I     0.0 I
                  I     0.0 I     0.0 I     0.0 I     0.0 I     3.2 I     0.0 I     0.0 I     0.0 I
                 -I---------I---------I---------I---------I---------I---------I---------I---------I
           COLUMN        15         6         1         2         3         1         2         1        31
            TOTAL      48.4      19.4       3.2       6.5       9.7       3.2       6.5       3.2     100.0
```

TABLE A-20. FIRING METHOD FOR COAL BY YEAR FOR EACH WATERTUBE CAPACITY CATEGORY (Continued) -- >500 KPH

FIRING	COUNT / ROW PCT / COL PCT / TOT PCT	YEAR 65.	66.	67.	69.	70.	71.	72.	73.	ROW TOTAL
-0.	COUNT	3	4	3	0	0	0	0	0	10
	ROW PCT	30.0	40.0	30.0	0.0	0.0	0.0	0.0	0.0	4.2
	COL PCT	6.4	10.8	9.1	0.0	0.0	0.0	0.0	0.0	
	TOT PCT	1.3	1.7	1.3	0.0	0.0	0.0	0.0	0.0	
PULVERIZED COAL 1.	COUNT	39	28	27	29	19	15	24	23	205
	ROW PCT	19.0	13.7	13.2	[illegible]	9.3	7.3	11.7	11.2	85.8
	COL PCT	83.0	75.7	81.8	[illegible]	90.5	72.7	92.3	100.0	
	TOT PCT	16.3	11.7	11.3	[illegible]	7.9	6.7	10.0	9.6	
OTHER SOLID 5.	COUNT	5	5	3	1	1	6	0	0	21
	ROW PCT	23.8	23.8	14.3	4.8	4.8	28.6	0.0	0.0	8.8
	COL PCT	10.6	13.5	9.1	3.3	4.8	27.3	0.0	0.0	
	TOT PCT	2.1	2.1	1.3	0.4	0.4	2.5	0.0	0.0	
NON-SOLID FUEL 9.	COUNT	0	0	0	0	1	0	2	0	3
	ROW PCT	0.0	0.0	0.0	0.0	33.3	0.0	66.7	0.0	1.3
	COL PCT	0.0	0.0	0.0	0.0	4.8	0.0	7.7	0.0	
	TOT PCT	0.0	0.0	0.0	0.0	0.4	0.0	0.8	0.0	
COLUMN TOTAL		47	37	33	30	21	22	26	23	239
		19.7	15.5	13.8	12.6	8.8	9.2	10.9	9.6	100.0

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS.

SIC CODE	COUNT ROW PCT COL PCT TOT PCT	PRIMARY FUEL -0.	BITUMINOUS COAL 1.	OIL 2.	NATURAL GAS 3.	WOODBARK 4.	BAGASSE 5.	BLACK LIQUOR 6.	OTHER FUELS 7.	WASTEHEAT 8.	WITH AUX. FIRING 9.	ROW TOTAL
NON-MANU	0.	6 0.2 26.1 0.1	312 11.3 52.3 3.4	802 29.1 30.5 8.6	1588 57.6 29.8 17.1	2 0.1 1.3 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	40 1.5 12.3 0.4	7 0.3 8.5 0.1	0 0.0 0.0 0.0	2759 29.6
	1.	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 100.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 0.0
	9.	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 100.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 0.0
OFFICES	15.	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 25.0 0.0 0.0	3 75.0 0.1 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	4 0.0
FOODS	20.	2 0.2 8.7 0.0	29 3.3 4.9 0.3	187 21.5 7.1 2.0	576 66.3 10.8 6.2	1 0.1 0.7 0.0	40 4.6 90.9 0.4	0 0.0 0.0 0.0	33 3.8 10.2 0.4	0 0.0 0.0 0.0	1 0.1 6.3 0.0	869 9.3
TOBACCO	21.	0 0.0 0.0 0.0	2 9.5 0.3 0.0	2 9.5 0.1 0.0	17 81.0 0.3 0.2	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	21 0.2
TEXTILES	22.	1 0.2 4.3 0.0	16 2.9 2.7 0.2	165 30.3 6.3 1.8	360 66.2 6.8 3.9	0 0.0 0.0 0.0	0 0.0 0.0 0.0	1 0.2 0.9 0.0	1 0.2 0.3 0.0	0 0.0 0.0 0.0	0 0.0 0.0 0.0	544 5.8
(CONTINUED)	COLUMN TOTAL	23 0.2	596 6.4	2628 28.3	5322 57.2	149 1.6	44 0.5	113 1.2	324 3.5	82 0.9	16 0.2	9302 100.0

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

```
                              PRIMARY FUEL
                  COUNT  I
                  ROW PCT ILIGNITE   NON-COMB    ROW
                  COL PCT I          US REMOV   TOTAL
 SIC CODE         TOT PCT I      10.I      12.I
                  --------I---------I---------I
                       0. I       0 I       1 I   2758
   NON-MANU               I     0.0 I     0.0 I   29.6
                          I     0.0 I   100.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                       1. I       0 I       0 I      1
                          I     0.0 I     0.0 I    0.0
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                       9. I       0 I       0 I      1
                          I     0.0 I     0.0 I    0.0
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                      15. I       0 I       0 I      4
   OFFICES                I     0.0 I     0.0 I    0.0
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                      20. I       0 I       0 I    869
   FOODS                  I     0.0 I     0.0 I    9.3
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                      21. I       0 I       0 I     21
   TOBACCO                I     0.0 I     0.0 I    0.2
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                      22. I       0 I       0 I    544
   TEXTILES               I     0.0 I     0.0 I    5.8
                          I     0.0 I     0.0 I
                          I     0.0 I     0.0 I
                         -I---------I---------I
                   COLUMN         4         1    9302
                    TOTAL       0.0       0.0   100.0
(CONTINUED)
```

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

SIC CODE	COUNT ROW PCT COL PCT TOT PCT	PRIMARY FUELS -0.	BITUMINOUS COAL 1.	OIL 2.	NATURAL GAS 3.	WOODBARK 4.	BAGASSE 5.	BLACK LIQUOR 6.	OTHER FUELS 7.	WASTEHEAT 8.	WITH AUX, FIRING 9.	ROW TOTAL
23.		0	6	0	1	0	0	0	0	0	0	1
		0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
24.		0	9	34	59	115	2	6	26	3	0	257
LUMBER		0.0	3.5	13.2	23.0	45.9	0.8	2.3	10.1	1.2	0.0	2.8
		0.0	1.5	1.3	1.1	79.2	4.5	5.3	8.0	3.7	0.0	
		0.0	0.1	0.4	0.6	1.3	0.0	0.1	0.3	0.0	0.0	
25.		0	1	0	2	0	0	0	0	0	0	3
		0.0	33.3	0.0	66.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
26.		1	25	146	182	26	1	106	20	15	0	522
PAPER		0.2	4.8	28.0	34.9	5.0	0.2	20.3	3.8	2.9	0.0	5.6
		4.3	4.2	5.6	3.4	17.4	2.3	93.8	6.2	18.3	0.0	
		0.0	0.3	1.6	2.0	0.3	0.0	1.1	0.2	0.2	0.0	
28.		3	37	264	666	0	1	0	61	12	3	1047
CHEMICALS		0.3	3.5	25.2	63.6	0.0	0.1	0.0	5.8	1.1	0.3	11.3
		13.0	6.2	10.0	12.5	0.0	2.3	0.0	18.8	14.6	18.7	
		0.0	0.4	2.8	7.2	0.0	0.0	0.0	0.7	0.1	0.0	
29.		0	6	143	312	1	0	0	84	13	6	565
PETROLEUMS		0.0	1.1	25.3	55.2	0.2	0.0	0.0	14.9	2.3	1.1	6.1
		0.0	1.0	5.4	5.9	0.7	0.0	0.0	25.9	15.9	37.5	
		0.0	0.1	1.5	3.4	0.0	0.0	0.0	0.9	0.1	0.1	
30.		0	3	71	141	0	0	0	1	1	0	217
RUBBER		0.0	1.4	32.7	65.0	0.0	0.0	0.0	0.5	0.5	0.0	2.3
		0.0	0.5	2.7	2.6	0.0	0.0	0.0	0.3	1.2	0.0	
		0.0	0.0	0.8	1.5	0.0	0.0	0.0	0.0	0.0	0.0	
	COLUMN TOTAL	23	596	2628	5322	149	44	113	324	82	16	9302
		0.2	6.4	28.3	57.2	1.6	0.5	1.2	3.5	0.9	0.2	100.0

(CONTINUED)

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

```
                        PRIMFUEL
              COUNT  I
             ROW PCT ILIGNITE   NON-COMB   ROW
             COL PCT I          US REMOV   TOTAL
 SIC CODE    TOT PCT I     10.I     12.I
             --------I--------I--------I
                 23. I      0 I      0 I      1
                     I    0.0 I    0.0 I    0.0
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 24. I      0 I      0 I    257
  LUMBER             I    0.0 I    0.0 I    2.8
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 25. I      0 I      0 I      3
                     I    0.0 I    0.0 I    0.0
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 26. I      0 I      0 I    522
  PAPER              I    0.0 I    0.0 I    5.6
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 28. I      0 I      0 I   1047
  CHEMICALS          I    0.0 I    0.0 I   11.3
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 29. I      0 I      0 I    565
  PETROLEUMS         I    0.0 I    0.0 I    6.1
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
                 30. I      0 I      0 I    217
  RUBBER             I    0.0 I    0.0 I    2.3
                     I    0.0 I    0.0 I
                     I    0.0 I    0.0 I
                    -I--------I--------I
              COLUMN        4        1     9302
               TOTAL      0.0      0.0    100.0
 (CONTINUED)
```

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

PRIMARY FUEL

SIC CODE COUNT ROW PCT COL PCT TOT PCT	-9.	BITUMINOUS COAL 1.	OIL 2.	NATURAL GAS 3.	WOODBARK 4.	BAGASSE 5.	BLACK LIQUOR 6.	OTHER FUELS 7.	WASTEHEAT 8.	WITH AUX. FIRING 9.	ROW TOTAL
31.	0	1	0	1	0	0	0	0	0	0	2
	0.0	50.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
33.	0	11	66	139	0	0	0	51	13	4	284
METAL	0.0	3.9	23.2	48.9	0.0	0.0	0.0	18.0	4.6	1.4	3.1
	0.0	1.8	2.5	2.6	0.0	0.0	0.0	15.7	15.9	25.0	
	0.0	0.1	0.7	1.5	0.0	0.0	0.0	0.5	0.1	0.0	
34.	0	0	0	3	0	0	0	0	0	0	3
FAB. METALS	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
35.	0	0	1	6	0	0	0	0	0	0	7
NON-E. MACH.	0.0	0.0	14.3	85.7	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	
37.	0	19	105	155	0	0	0	3	0	1	283
TRANSPORTATION	0.0	6.7	37.1	54.9	0.0	0.0	0.0	1.1	0.0	0.4	3.0
	0.0	3.2	4.0	2.9	0.0	0.0	0.0	0.9	0.0	6.3	
	0.0	0.2	1.1	1.7	0.0	0.0	0.0	0.0	0.0	0.0	
39.	1	16	191	411	1	0	0	2	5	0	627
MISC-MANU	0.2	2.6	30.5	65.6	0.2	0.0	0.0	0.3	0.8	0.0	6.7
	4.3	2.7	7.3	7.7	0.7	0.0	0.0	0.6	6.1	0.0	
	0.0	0.2	2.1	4.4	0.0	0.0	0.0	0.0	0.1	0.0	
49.	9	93	230	95	0	0	0	1	12	1	445
ELEC UTILITIES	2.0	20.9	51.7	21.3	0.0	0.0	0.0	0.2	2.7	0.2	4.8
	39.1	15.6	8.8	1.8	0.0	0.0	0.0	0.3	14.6	6.3	
	0.1	1.0	2.5	1.0	0.0	0.0	0.0	0.0	0.1	0.0	
COLUMN TOTAL	23	596	2628	5322	149	44	113	324	82	16	9382
	0.2	6.4	28.3	57.2	1.6	0.5	1.2	3.5	0.9	0.2	100.0

(CONTINUED)

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

```
                        PRIMARY FUEL
               COUNT  I
             ROW PCT  ILIGNITE   NON-COMB    ROW
             COL PCT  I          US REMOV   TOTAL
SIC CODE     TOT PCT  I     10.I     12.I
             ---------I---------I---------I
                 31.  I      0  I      0  I      2
                      I    0.0  I    0.0  I    0.0
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 33.  I      0  I      0  I    284
 METAL                I    0.0  I    0.0  I    3.1
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 34.  I      0  I      0  I      3
 FAB. METALS          I    0.0  I    0.0  I    0.0
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 35.  I      0  I      0  I      7
 NON-E. MACH.         I    0.0  I    0.0  I    0.1
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 37.  I      0  I      0  I    283
 TRANSPORTATION       I    0.0  I    0.0  I    3.0
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 39.  I      0  I      0  I    627
 MISC-MANU            I    0.0  I    0.0  I    6.7
                      I    0.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
                 49.  I      4  I      0  I    445
 ELEC UTILITIES       I    0.9  I    0.0  I    4.8
                      I  100.0  I    0.0  I
                      I    0.0  I    0.0  I
                     -I---------I---------I
              COLUMN         4         1      9302
               TOTAL       0.0       0.0     100.0
(CONTINUED)
```

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

```
                            PRIMARY FUEL
                 COUNT   I
                 ROW PCT ILIGNITE   NON-COMB   ROW
                 COL PCT I          US REMOV   TOTAL
SIC CODE         TOT PCT I      10.I      12.I
                 --------I---------I---------I
                     55. I       0 I       0 I       2
  APARTMENTS             I     0.0 I     0.0 I     0.0
                         I     0.0 I     0.0 I
                         I     0.0 I     0.0 I
                        -I---------I---------I
                     80. I       0 I       0 I     537
  HOSPITALS              I     0.0 I     0.0 I     5.8
                         I     0.0 I     0.0 I
                         I     0.0 I     0.0 I
                        -I---------I---------I
                     82. I       0 I       0 I     302
  SCHOOLS                I     0.0 I     0.0 I     3.2
                         I     0.0 I     0.0 I
                         I     0.0 I     0.0 I
                        -I---------I---------I
                  COLUMN         4         1     9302
                   TOTAL       0.0       0.0    100.0
```

TABLE A-21. PRIMARY FUEL BY STANDARD INDUSTRIAL CODE FOR WATERTUBE BOILERS (Continued)

SIC CODE	PRIMARY FUEL: COUNT / ROW PCT / COL PCT / TOT PCT	-0.	BITUMINO US COAL 1.	OIL 2.	NATURAL GAS 3.	WOODBARK 4.	BAGASSE 5.	BLACK LIQUOR 6.	OTHER FUELS 7.	WASTEHEAT 8.	WITH AUX . FIRING 9.	ROW TOTAL
65. APARTMENTS	COUNT	0	0	0	2	0	0	0	0	0	0	2
	ROW PCT	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	COL PCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	TOT PCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
80. HOSPITALS	COUNT	0	4	139	394	0	0	0	0	0	0	537
	ROW PCT	0.0	0.7	25.9	73.4	0.0	0.0	0.0	0.0	0.0	0.0	5.8
	COL PCT	0.0	0.7	5.3	7.4	0.0	0.0	0.0	0.0	0.0	0.0	
	TOT PCT	0.0	0.0	1.5	4.2	0.0	0.0	0.0	0.0	0.0	0.0	
82. SCHOOLS	COUNT	0	12	81	207	0	0	0	1	1	0	302
	ROW PCT	0.0	4.0	26.8	68.5	0.0	0.0	0.0	0.3	0.3	0.0	3.2
	COL PCT	0.0	2.0	3.1	3.9	0.0	0.0	0.0	0.3	1.2	0.0	
	TOT PCT	0.0	0.1	0.9	2.2	0.0	0.0	0.0	0.0	0.0	0.0	
COLUMN TOTAL		23	596	2628	5322	149	44	113	324	82	16	9302
		0.2	6.4	28.3	57.2	1.6	0.5	1.2	3.5	0.9	0.2	100.0

(CONTINUED)

TABLE A-22. PRIMARY FUEL BY GEOGRAPHIC REGIONS
(See Page A-28 for state/region definitions)

PRIMFUEL	REGION COUNT ROW PCT COL PCT TOT PCT	not Coded 0.	N.Eng. 1.	M-Atl. 2.	E-N-C 3.	S-Atl. 4.	W-N-C 5.	W-S-C 6.	R.Mtn. 7.	NW 8.	SW 9.	ROW TOTAL
.	0.	0	0	0	2	0	2	4	0	0	0	8
		0.0	0.0	0.0	25.0	0.0	25.0	50.0	0.0	0.0	0.0	0.1
		0.0	0.0	0.0	0.1	0.0	0.3	0.4	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
BITUMINOUS COAL	1.	1	5	106	244	89	58	18	32	14	12	579
		0.2	0.9	18.3	42.1	15.4	10.0	3.1	5.5	2.4	2.1	6.5
		0.9	1.1	5.2	12.1	5.8	8.9	1.7	13.8	4.4	2.2	
		0.0	0.1	1.2	2.7	1.0	0.6	0.2	0.4	0.2	0.1	
OIL	2.	69	299	1020	327	384	97	86	21	39	101	2443
		2.8	12.2	41.8	13.4	15.7	4.0	3.5	0.9	1.6	4.1	27.3
		61.1	64.2	50.2	16.2	25.0	14.8	8.3	9.1	12.2	18.5	
		0.8	3.3	11.4	3.7	4.3	1.1	1.0	0.2	0.4	1.1	
NATURAL GAS	3.	32	146	787	1371	912	480	764	169	209	380	5250
		0.6	2.8	15.0	26.1	17.4	9.1	14.6	3.2	4.0	7.2	58.6
		28.3	31.3	38.7	67.8	59.5	73.4	73.7	72.8	65.5	69.5	
		0.4	1.6	8.8	15.3	10.2	5.4	8.5	1.9	2.3	4.2	
WOODBARK	4.	0	4	16	9	49	0	24	1	20	21	144
		0.0	2.8	11.1	6.3	34.0	0.0	16.7	0.7	13.9	14.6	1.6
		0.0	0.9	0.8	0.4	3.2	0.0	2.3	0.4	6.3	3.8	
		0.0	0.0	0.2	0.1	0.5	0.0	0.3	0.0	0.2	0.2	
BAGASSE	5.	0	0	0	9	4	1	18	0	0	3	35
		0.0	0.0	0.0	25.7	11.4	2.9	51.4	0.0	0.0	8.6	0.4
		0.0	0.0	0.0	0.4	0.3	0.2	1.7	0.0	0.0	0.5	
		0.0	0.0	0.0	0.1	0.0	0.0	0.2	0.0	0.0	0.0	
BLACK LIQUOR	6.	1	6	8	8	40	4	17	0	25	0	109
		0.9	5.5	7.3	7.3	36.7	3.7	15.6	0.0	22.9	0.0	1.2
		0.9	1.3	0.4	0.4	2.6	0.6	1.6	0.0	7.8	0.0	
		0.0	0.1	0.1	0.1	0.4	0.0	0.2	0.0	0.3	0.0	
COLUMN TOTAL		113	466	2031	2021	1534	654	1037	232	319	547	8954
		1.3	5.2	22.7	22.6	17.1	7.3	11.6	2.6	3.6	6.1	100.0

(CONTINUED)

TABLE A-22. PRIMARY FUEL BY GEOGRAPHIC REGIONS (Continued)
(See Page A-28 for state/region definition)

PRIMFUEL	COUNT ROW PCT COL PCT TOT PCT	REGION not Coded 0.	N.Eng. 1.	M-Atl. 2.	E-N-C 3.	S-Atl. 4.	W-N-C 5.	W-S-C 6.	R.Mtn. 7.	NW 8.	SW 9.	ROW TOTAL
7.		10	5	72	38	43	12	80	1	12	10	283
OTHER FUELS		3.5	1.8	25.4	13.4	15.2	4.2	28.3	0.4	4.2	3.5	3.2
		8.8	1.1	3.5	1.9	2.8	1.8	7.7	0.4	3.8	1.8	
		0.1	0.1	0.8	0.4	0.5	0.1	0.9	0.0	0.1	0.1	
8.		0	1	17	5	13	0	19	7	0	20	82
WASTEHEAT		0.0	1.2	20.7	6.1	15.9	0.0	23.2	8.5	0.0	24.4	0.9
		0.0	0.2	0.8	0.2	0.8	0.0	1.8	3.0	0.0	3.7	
		0.0	0.0	0.2	0.1	0.1	0.0	0.2	0.1	0.0	0.2	
9.		0	0	4	6	0	0	5	1	0	0	16
WITH AUX. FIRING		0.0	0.0	25.0	37.5	0.0	0.0	31.3	6.3	0.0	0.0	0.2
		0.0	0.0	0.2	0.3	0.0	0.0	0.5	0.4	0.0	0.0	
		0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	
10.		0	0	0	2	0	0	2	0	0	0	4
LIGNITE		0.0	0.0	0.0	50.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.1	0.0	0.0	0.2	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
12.		0	0	1	0	0	0	0	0	0	0	1
NON-COMBUS REMOV		0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
COLUMN		113	466	2031	2021	1534	654	1037	232	319	547	8954
TOTAL		1.3	5.2	22.7	22.6	17.1	7.3	11.6	2.6	3.6	6.1	100.0

NUMBER OF MISSING OBSERVATIONS = 348 (Primary fuel data missing from input card)

RECENT SALES OF FIRETUBE BOILERS

Firetube boilers are available in the industrial size range in sizes up to about 900 BHP (or 30,000 PPH). They are most common in sizes below 500 BHP. ABMA records on sales of firetube boilers do not contain as much detail as for watertube boilers regarding combinations of features. However, in recent years, most firetube boilers in the industrial size range have been of the packaged Scotch design. ABMA data on sales of packaged Scotch boilers during the period 1965-1972 are summarized in Tables A-23 and A-24.

Table A-23 shows recent sales of packaged Scotch firetube boilers tabulated by capacity in boiler horsepower. Most of these sales are in the commercial size range; only 14 percent fall in the industrial size range. The most popular sizes in the commercial range are 100 and 150 BHP and 600 BHP in the industrial range.

Table A-24 shows the sales of Scotch boilers by years, with the percentage distribution by fuels. Over the period 1965 through 1972, 38 percent were oil fired, 32 percent gas fired, and 30 percent equipped for dual-fuel or combination oil/gas firing. A gradual decrease in oil-fired units during the period was accompanied by a shift to combination units, except in the last few years oil-fired units gained as gas-fired units were displaced by both oil and combination units.

TABLE A-23. RECENT SALES OF PACKAGED SCOTCH FIRETUBE BOILERS BY CAPACITY (1965-1972)

Capacity, boiler horsepower	Number of Units	Percent of Total
Commercial Range		
<15	728	1.7
20	898	2.0
25	425	1.0
30	2,060	4.7
40	1,976	4.5
50	2,263	5.1
60	2,928	6.7
70	1,189	2.7
80	2,630	6.0
100	4,971	11.2
125	3,757	8.6
150	4,305	9.8
200	4,548	10.3
225	205	0.5
250	2,454	5.6
Industrial Range		
300	2,572	5.9
350	1,385	3.2
400	1,319	3.0
500	1,392	3.2
600	1,670	3.8
>700	212	0.5
Total	43,887	100.0%

TABLE A-24. SALES OF PACKAGED SCOTCH WATERTUBE BOILERS BY YEAR AND FUEL - (1965-1972)

Year	Total Number of Boiler Units		Distribution by Fuel, percent		
			Oil	Gas	Combination
'65	6,520		43.0	33.5	23.5
'66	6,611		42.8	33.0	24.2
'67	5,515		38.7	33.0	28.3
'68	5,292		35.9	35.3	28.8
'69	6,580		35.2	36.9	27.9
'70	4,732		32.7	33.5	33.8
'71	4,422		34.8	26.4	38.8
'72	4,215		41.3	21.3	37.4
Total	43,887	8-year Average	38.3	32.2	29.5

Recent Boiler Sales in Terms of Total Capacity

Firetube Boilers. Table A-25 summarizes recent sales of packaged Scotch boilers in the commercial-industrial range, both in number of units and in total capacity (PPH). While the Scotch boilers in the industrial size range represent only 14 percent of the total Scotch boiler units, they account for 38 percent of the total capacity of Scotch boilers.

Watertube Boilers. Table A-26 summarizes recent sales of non-utility watertube boilers by size range, showing the number of units and the total installed capacity. Boilers of 250,000 PPH and below represent about 98 percent of the total watertube boiler units, but they account for only 85 percent of the total capacity.

Figure A-1 shows graphically the accumulative distribution of non-utility boilers (firetube and watertube boiler capacity added per year). This illustrates the contribution of the large numbers of smaller units in making up the total installed capacity.

Inventory of Installed Capacity of Current Boiler Population

To examine the total installed capacity of the current field population of industrial boilers, the estimates by Walden for 1967 were updated to 1972 using ABMA data for the period.(10)

Table 27 summarizes the distribution of total installed capacity by boiler type and size category, showing the Walden estimate for 1967 and the 1972 update. The total installed capacity of industrial boilers was estimated to be 2.45×10^9 PPH for 1972.* Of this capacity, 90 percent is contributed by boilers of watertube construction and 10 percent by those of firetube construction.

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* It is interesting to note that the total installed capacity of boilers used in industry is nearly as great as the capacity of boilers serving electrical utilities. The total installed capacity of industrial boilers in 1967 was estimated in the Walden study to be about 85 percent of the utility capacity.

TABLE A-25. SUMMARY OF SALES OF PACKAGED SCOTCH FIRETUBE BOILERS--NUMBER OF UNITS AND TOTAL CAPACITY BY SIZE CATEGORIES (1965-1972)

Boiler Size Range, horsepower	Number of Units		Total Capacity	
	Units	Percent	10^6 PPH	Percent
Commercial Range				
10-50 BHP	8,351	19.0	9.9	3.9
51-100 BHP	11,718	26.6	32.3	12.8
101-300 BHP	17,877	40.7	115.4	45.6
Industrial Range				
301-500 BHP	4,096	9.4	57.0	22.5
>501 BHP	1,882	4.3	38.3	15.2
Total	43,889	100.0	252.9	100.0

TABLE A-26. SALES OF WATERTUBE BOILERS -- NUMBER OF UNITS AND TOTAL INSTALLED CAPACITY (1965-October 1973)

(Not Including Boilers For)
Utility Electrical Generation)

Boiler Capacity Range	Boiler Units		Total Capacity,	
	Number	Percent	10^6 PPH	Percent
100,000 and less	6,000	76.5	237.7	43.5
100,001 to 250,000	1,643	21.0	225.1	41.2
250,001 to 500,000	177	2.2	56.4	10.3
over 500,000	27	0.3	27.2	5.0
Total	7,820	100.0	546.4	100.0

TABLE A-27. INVENTORY ESTIMATE OF TOTAL INSTALLED CAPACITY FOR INDUSTRIAL BOILERS

(Firetube and Watertube Boilers
Operating in the United States
at the End of 1972)

Boiler Type and Size Range	Total Installed Capacity, 10^6 PPH 1967 Inventory (a)	 1972 Update (b)
Firetube		
>10,000 PPH (>300 HP)	192 (c)	250 (d)
Watertube		
10,000-100,000 PPH	921	1,090
100,001-250,000 PPH	658	800
250,001-500,000 PPH	259	310
Total	2,030	2,450

a. Walden estimate of capacity operating in 1967 (Reference 10).

b. Update through 1972, using Walden estimate of capacity for 1967, plus ABMA sales data on non-utility watertube boilers and Scotch firetube boilers.

c. Derived from Walden estimate for commercial-industrial boilers by deducting watertube capacity.

d. Including firebox firetube boilers in this range as 5 percent of the Scotch boiler capacity.

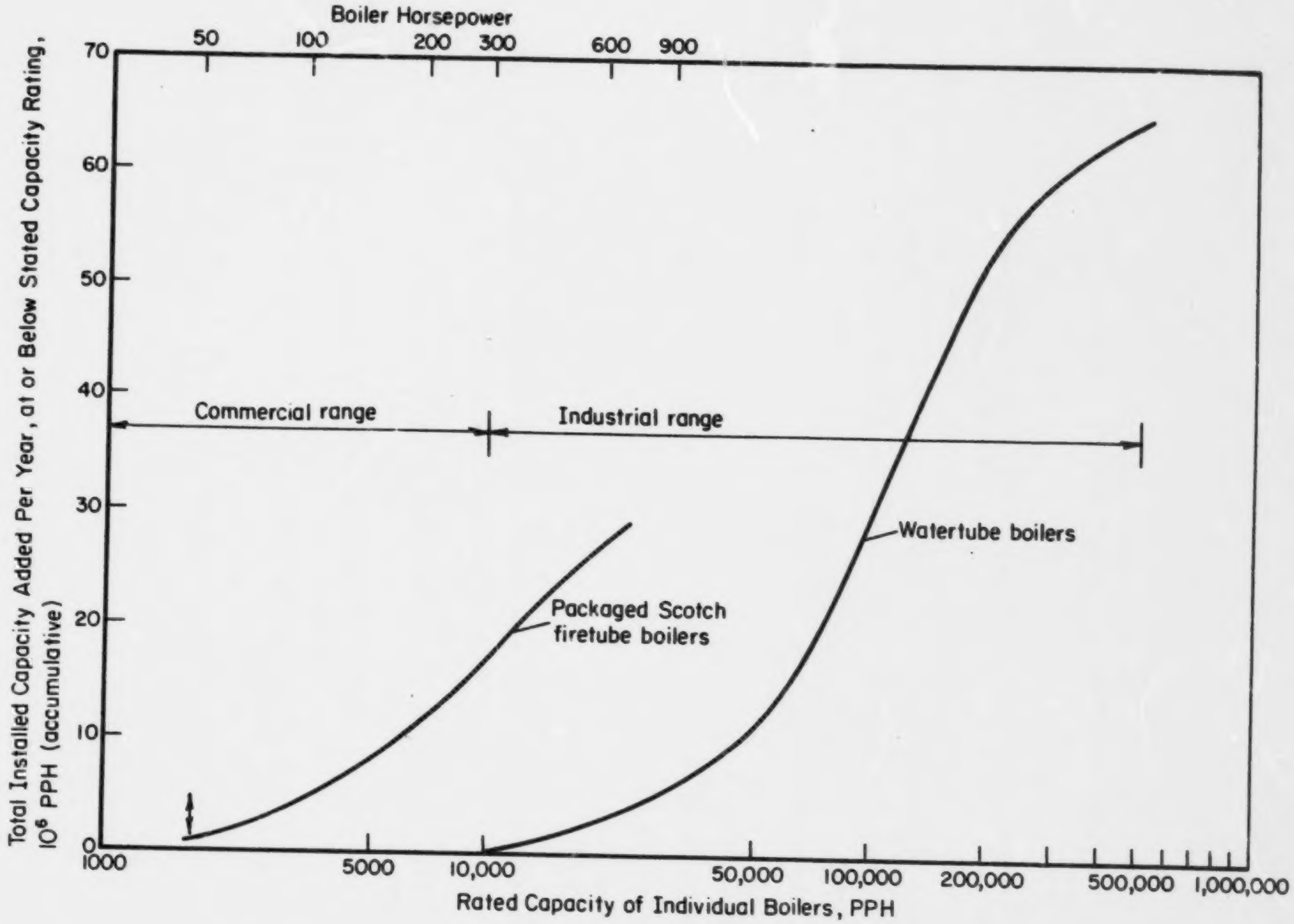

FIGURE A-1. TOTAL ANNUAL INSTALLED CAPACITY OF INDUSTRIAL BOILERS – DISTRIBUTION BY BOILER SIZE FOR WATERTUBE AND PACKAGED SCOTCH FIRETUBE BOILERS

APPLICABILITY OF COMBUSTION MODIFICATION TO INDUSTRIAL BOILERS

The feasibility of applying combustion modification techniques to industrial boilers varies with boiler design and particular circumstances of the installation. The effectiveness, practical difficulty, and cost of the modification are also subject to much variation with conditions. However, a general assessment was made of the practical feasibility of applying various modification techniques to various boilers, without considering the effectiveness of each. Other investigations have considered effects of combustion modifications on emissions.(15-19)

Table A-28 provides an overview of the relative applicability of the following combustion techniques to firetube and watertube boilers in the industrial size range:

- Burner design changes
- Low-excess air firing
- Steam or water injection
- Biased firing
  (for multiple-burner units)
- Staged combustion
  (no ports)
- Flue-gas recirculation

Current studies will provide additional insight and experience as to the applicability of these modifications to industrial boilers.(16)

* * * * *

Parts B and C of this report cover potential problems associated with combustion modification:

Part B. Corrosion and Deposits
Part C. Flame Stability

TABLE A-28. APPLICABILITY OF COMBUSTION MODIFICATION TO VARIOUS TYPES OF BOILERS
(Does not imply relative effectiveness for NO_x reduction)

Combustion Modification[(a)]	Fuel	Burner Design	Low-Excess Air Firing	Steam or Water Injection	Biased Firing (b)	Staged Combustion (c)	Flue-gas Recirculation
FIRETUBE BOILERS							
Packaged Scotch	gas/oil	●●●	●●●	●●●	N/A	●●	●●
Firebox	gas/oil	●●●	●●●	●●●	N/A	●●	●●
	stoker	N/A	N/A	●●●	N/A	●	●●
WATERTUBE BOILERS	gas/oil	●●●	●●●	●●●	●●●	●●	●●
	stoker	N/A	N/A	●●●	N/A	●	●●
	PC	●●	●●	●●●	●●●	●●	●●

Notes: (a) Applicability of combustion modification

●●● Modification is feasible for new boilers and for retrofit (consistent with other criteria)

●● Modification is feasible for new boilers and for retrofit, but with considerable difficulty (re cutting boiler tubes or overall cost)

● Modification is feasible only for entirely new designs

(b) Only applicable for multiple burners.

(c) Staged combustion includes use of NO-ports downstream of rich burning zone.

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PART B

FIRESIDE CORROSION AND DEPOSITS AS AFFECTED BY COMBUSTION MODIFICATIONS

by

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March, 1974

PART B

FIRESIDE CORROSION AND DEPOSITS AS AFFECTED BY COMBUSTION MODIFICATIONS

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PART B

FIRESIDE CORROSION AND DEPOSITS AS AFFECTED BY COMBUSTION MODIFICATIONS

by

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BATTELLE
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In the history of boiler furnace operation, increased corrosion and deposit problems have been associated with changes in fuels, fuel-firing techniques, surface temperatures, and other combustion variables. The current emphasis on environmental quality has brought about the need for generating power and steam with less emission of air pollutants. Combustion modification offers a solution to at least part of the problem, but the changes in furnace conditions resulting from modifications such as low-excess air or two-stage firing have a potential for introducing new corrosion and deposit problems.

TASK OBJECTIVES

The specific aims of this task are to:

(1) Assess the corrosion and deposit problems that are likely to result from combustion modification.

(2) Determine whether or not solutions to the potential problems are known.

(3) Recommend specific research directed toward providing solutions where none are known.

EFFECTS OF LOW-EXCESS AIR

From the viewpoint of air-pollution control, operation of boilers with low-excess air is designed to reduce the formation of nitrogen oxides, but it will have other effects on the chemistry of the combustion system as well. Reduction of the amount of combustion air can affect substantial lowering of the SO_3 concentration in the boiler, and it will also minimize the conversion of the vanadium in residual oil to low-melting-corrosive compounds. However, present technology has limited the use of low-excess air to oil-burning systems.

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Reduction of SO_3 Concentration

In terms of corrosion by SO_3 and the various compounds formed from it, the effects of operating boiler furnaces with low-excess air are beneficial. Experience with oil-fired systems, where low-excess-air operation is most practical at the present time, has demonstrated that this mode of operation minimizes superheater deposits, essentially prevents high-temperature-metal wastage, stops air-preheater corrosion, and eliminates emission of acid smuts. This subject has been thoroughly discussed by W. T. Reid in his book on Corrosion and Deposits.(1) Successful operation with low-excess air requires that the oxygen in the flue gas be maintained less than about 0.2 percent. This requires precise control of the fuel-air ratio in all parts of the combustion system to prevent fuel-rich zones with subsequent thermal cracking of hydrocarbons and the emission of smoke. Consequently low-excess-air operation has in the past been limited to oil-fired systems, because the technology for burning pulverized coal with such little oxygen has not yet been developed. Normal operation with 12 to 20 percent excess air results in the formation of 25 to 30 ppm SO_3 in the flame with fuels containing 2-3 percent sulfur. The excess air must be less than 2 percent to decrease the SO_3 by about half. Further lowering of the excess air results in a rapid drop of the SO_3 level, and at about 0.1 percent oxygen in the flue gas the SO_3 concentration will be reduced essentially to zero.

A typical example of the reduction in corrosion that can be obtained by low-excess-air-operation was reported by Attig and Sedor for a furnace operating with residual oil containing 4 percent sulfur.(2) Corrosion rates for carbon steel were reduced from about 90 mils per year to about 8 mils per year in a 200 F temperature zone, by decreasing the excess air from 9.5 percent to 1.5 percent. In the 350 F zone the corrosion rate was well under 5 mils per year. An even more significant reduction in corrosion was obtained by Glaubitz, who operated oil-fired boilers at 0.3 percent excess air.(3,4) By reducing the excess air to this level from the previous level of 7 percent, a 16-fold decrease in corrosion was achieved when burning an oil containing 3.3 percent sulfur. According to a report of Russian experience with oil containing 2.5 to 3.0 percent sulfur, corrosion rates were reduced at least 4-fold by decreasing the excess air from the usual 10 percent to 2 to 3 percent.(5) Boiler furnace operation with low-excess air has been pioneered in Germany and England, but this technique has not been widely practiced in the United States. However, new boiler installations are incorporating this capability.(6)

Corrosion of wall tubes in boilers, particularly those fired with coal, has been found to be caused by low-melting pyrosulfates and trisulfates.(7,8,9) These compounds all depend on the presence of SO_3 for their formation, and the corrosion mechanisms involving these compounds require the availability of high concentrations of SO_3. In the superheaters, the tube temperature is too high for pyrosulfates to exist, but corrosion by the trisulfates has been serious enough to limit steam temperatures to the range 1000-1050 F.(1) Consequently, minimizing the amount of SO_3 in the flue gases by using low-excess-air combustion will reduce the corrosion from these complex sulfates, on both wall tubes and superheaters.

Reduction of Vanadium Corrosion

Another beneficial effect of low-excess-air operation is the reduction of high-temperature corrosion which results from the vanadium content of residual oils. When the vanadium is oxidized to the pentavalent state, low-melting compounds such as vanadium pentoxide (V_2O_5) and various sodium vanadates are formed. Operation with low-excess air, however, limits the oxidation of vanadium to compounds such as V_2O_3 or V_2O_4 which are high-melting compounds and do not cause corrosion as do the easily fusible salts.

This effect has been demonstrated by Chaikivsky and Siegmund, who burned residual oil containing 350 ppm vanadium and 2.57 percent sulfur in a laboratory combustor.(10) With 15 percent excess air almost all of the vanadium appeared in the tube deposits as the very corrosive sodium vanadyl vanadate. At 5 percent excess air, significant amounts of the lower-vanadium oxides were formed, and below 4 percent excess air there was an abrupt decrease in both corrosion and deposits, as the lower oxides predominated.

From these considerations it must be concluded that as long as strongly reducing conditions are not created in localized areas, operation of boiler furnaces with low-excess air will reduce corrosion. The benefits of low-excess air will be reflected in longer life of all of the elements of the boiler, from wall tubes to superheater elements and convection surfaces, through the low-temperature end, including economizer and air preheater. However, as mentioned previously, at the present time low-excess-air operation has only been adapted to oil-firing systems.

Problems in Burning Pulverized Coal With Low-Excess Air

Central-station boiler plants burning pulverized coal usually operate with excess air ranging between about 12 and 20 percent. At higher levels, excessive sensible heat is lost in the stack gas, and at lower levels too much unburned carbon leaves the furnace with the flyash. This unburned carbon represents a serious heat loss and it can be a grave source of trouble if it becomes ignited and burns in ash hoppers later in the boiler circuit.

The reactivity of the coal probably plays a part in establishing the amount of unburned carbon leaving the furnace, but the main problem undoubtedly is the combustion mode of particles of pulverized coal, where devolatilization occurs first with immediate burning of the volatile matter followed by slower combustion of the remaining particle of "char". Because that residual-carbonaceous particle is relatively inert compared with a droplet of fuel oil, more excess air is required to burn it in the few milliseconds available than suffices for complete combustion of liquid droplets. Hence, the same few precautions taken when burning fuel oil with low-excess air--of insuring fine droplet size and carefully proportioning fuel and air for stoichiometric combustion--will not be adequate when burning solid particles of coal.

Basically, then, to simulate the conditions leading to successful burning of fuel oil with low-excess air, pulverized coal firstly must be finely ground to produce particles with the highest possible surface area to compensate for its lesser reactivity than fuel oil. The conventional grind of 85 percent of the coal through a 200-mesh sieve--or 74 micrometers--must be changed to provide finer particles, but the actual particle size necessary is in doubt.

Secondly, proportioning of air and coal at each burner will need more consideration than is given at present. Great care will be necessary to insure precisely the coal and air distribution to each flame element to be certain that complete burning will take place. Any fuel-rich flame zones will lead to solid-carbonaceous particles probably too inert to react with carbon dioxide and water vapor as the particles move out of the flame zone into cooler parts of the boiler furnace.

Thirdly, residence time at high temperature must be long. It appears possible that corner firing leading to a flame vortex may result in longer residence time in a high-temperature zone than would be expected in a wall-fired furnace. In addition, the intermixing at different burner streams in corner firing may minimize the importance of proportioning fuel and air to each burner. More data are needed here to substantiate this theoretically attractive possibility.

Fourthly, burners must be designed for gradual mixing of coal and air at moderate temperatures to minimize conversion of fuel nitrogen to NO_x, although this increases the difficulty of carbon burnout later in the flame. In the later stages of combustion it appears necessary to maintain high temperature and assure adequate turbulence for carbon burnout. A better understanding of these techniques is being gained in research on fundamentals of pulverized coal combustion, such as that at IJmuiden(11).

Fifthly, basic differences in the nature of devolatilized char from different coals need to be evaluated. Obvious problems in burning pulverized anthracite have been recognized for many years, but less clear are the factors involved between bituminous coals, subbituminous coals, and lignite. Recent experience has shown that burning low-rank coals from Montana in cyclone furnaces intended to burn bituminous coal from southern Illinois has led to serious problems with unburned carbon leaving the furnace. It is not clear presently whether this is mainly the result of differences in reactivity or of other factors inherent in cyclone furnaces. It is evident, though, that coal reactivity depends upon other factors than volatile matter content as determined by a proximate analysis.

These arguments apply mainly to the burning of pulverized coal. They apply with almost equal importance to spreader stokers or to fast-fluidized beds where burning in suspension is significant. They do not apply to fixed-fuel beds, such as with chain-grate or underfeed stokers. In those cases, combustion occurs in two distinct stages either within the fuel bed for thin beds, or within the bed and above it for thick fuel beds which act like gas producers. Usual practice in stoker-fired installations is to supply an excess of overfire air, frequently through high-velocity jets, to burn the carbon monoxide and hydrogen plus any volatile matter leaving the fuel bed. A highly sophisticated secondary air system with overfire jets can minimize the amount of excess air needed, but probably never to the level achievable with the best pulverized-coal systems.

EFFECTS OF TWO-STAGE COMBUSTION

The use of two-stage combustion to reduce air pollution requires that the first stage be a fuel-rich zone. Under these conditions the combustion is not complete and a reducing atmosphere predominates in this region. As a result, the oxidation of the sulfur and the carbon will not be complete, and corrosion might occur quite differently than in an oxidizing atmosphere.

Sulfide Corrosion

In an oxygen-deficient atmosphere the sulfur from the decomposition of pyrites, FeS_2, will not all be oxidized to sulfur dioxide. The first step in the combustion of FeS_2 is a dissociation in which an atom of sulfur is released. An experimental study of the reaction under conditions that would exist in a furnace showed that this sulfur was released in 0.5 sec at a temperature of 2000 F.(12) The pressure of the sulfur vapor thus formed reaches one atmosphere at 1435 F. The experiments demonstrated that with the short residence time in the flame, sulfur and metal sulfides could be deposited on furnace-wall tubes.

The presence of FeS in the deposits found on badly corroded boiler tubes has been reported by W. T. Reid and his associates.(7) In 7 of the furnaces that they examined in the early 1940's, sulfide deposits were found in some areas. Up to 5 percent carbon also was noted in some of these deposits, indicating that the normal oxidation process had not occurred. Later Corey, et al, demonstrated by laboratory experiments that iron is corroded rapidly in the presence of FeS_2 in the temperature range 700-1000 F.(9) Under these conditions corrosion by FeS was negligible, indicating that the sulfur released in the decomposition of FeS_2 was responsible for the attack. Considering these experiments in the light of the conditions that prevailed in the furnace, it was concluded that poor distribution of the coal stream leaving the burners, coupled with coarse pulverization, resulted in deposition of incompletely burned coal on the furnace walls. The FeS_2 carried with this coal oxidized slowly, evolving sulfur, which then could react with the tube metal to give the deposit of FeS, some of which subsequently oxidized to Fe_3O_4. Both of these compounds were identified in the deposit by X-ray diffraction analysis.

Additional evidence for this mechanism was obtained when corrective measures were applied in two of the furnaces having severe corrosion in areas with FeS deposits. Both the rapid corrosion and the FeS were eliminated when mill adjustments were made and coal-distributor pipes were repaired, thus insuring that the carbon and the sulfur would be completely oxidized before reaching the wall tubes.

No data are available on the extent or duration of reducing conditions required to convert the alkali-iron trisulfates into sulfides. It is probable that the ratio of H_2 to H_2O and of CO to CO_2 must be fairly high for that conversion to occur. Probably more important here is that the trisulfates will not form except in the presence of SO_3, some 250 ppm being necessary to 1000 F to produce these compounds. Since, as has been shown conclusively in studies of combustion with low-excess air, SO_3 is not formed when the oxygen level in the flue gas is less than about 0.2 percent, it is highly probable that there will be no trisulfates formed under such conditions. However, the oxygen-deficient conditions may lead to deposition of sulfur or pyrites, with the consequent corrosion of the boiler tubes.

Sulfide corrosion is particularly serious when the tube metal being attacked contains nickel and the corrosion propagates along the grain boundaries. The resulting nickel sulfides are low-melting compounds, and being liquids of more than one valence state can freely transport sulfur from the mouth of a grain boundary deeper into the grain boundary. In the case of chromium, the sulfides which form do not melt as readily and therefore do not migrate as freely. Accordingly, chromium-base alloys are more resistant to sulfide corrosion than are nickel-base alloys.(13,14) Unfortunately, the chromium-base alloys have inferior high-temperature strength.

Effects of Carbon Monoxide

Incomplete combustion of carbon in a fuel-rich zone will result in an increase in CO concentration. There is no direct action of CO on boiler steels to cause metal wastage when the concentration is low. However, there can be an indirect effect of the CO in reducing the thickness of the oxide scale, thereby exposing fresh tube metal to oxidative attack when conditions change from reducing to oxidizing. Rasch has shown that the reduction sequence $Fe_2O_3 \rightarrow Fe_3O_4 \rightarrow FeO$ can occur when the ratio of CO to CO_2 is 1 to 1 and will take place at lower temperatures as the amount of CO predominates over CO_2.(15) Furthermore, the CO can reduce FeO to Fe via an intermediate of Fe_3C, thus removing all of the protective oxide layer from the tube. Subsequent oxidation of the unprotected metal will then occur if alternating oxidizing and reducing conditions are present.

Excessive loss of tube metal in large steam-generating incinerators in Europe has been attributed to this action. The poor combustion conditions in fuel beds burning raw garbage results in flames reaching wall tubes one moment and air the next, so that the atmosphere over the wall tubes is alternately highly reducing and highly oxidizing.

Corrosion at the Stuttgart incinerator in Germany was attributed to these causes.(16) The CO concentration was about 0.2 percent, with unburned carbon in the form of glowing particles impinging on the wall tubes. Although the wall tubes were only at a temperature of 570 F, their failure frequency was 10 times as great as that of the convection tubes. Some of the superheater tubes failed in just one year, and others after 4 years. This catastrophic corrosion was alleviated by redesigning the combustion chamber and by putting studs on the tubes in vulnerable areas and packing the studded area with silicon carbide.

At the Munich incinerator, wall tubes subject to a reducing atmosphere decreased in thickness from 3.2 mm to 1.8 mm in 3500 hours.(17) Flame impingement and alternate oxidizing and reducing atmospheres were blamed for corrosion that required replacement of 100 boiler tubes. In this case also, the silicon-carbide packing was used as a remedy. In addition the superheater tubes were shielded with Sicromal alloy to reduce corrosion. No definite proof exists as yet that tube wastage is always accelerated by such alternating conditions, but this is a point worthy of consideration since two-stage combustion very likely will lead to a zone intermediate between the two combustion zones where the furnace atmosphere may shift rapidly and unpredictably between reducing and oxidizing conditions.

EFFECTS OF FLUE-GAS RECIRCULATION

Recirculation of flue gas probably will tend to minimize the formation of the alkali-iron trisulfates because not enough oxygen may then be present to form the needed SO_3. If enough CO_2, water vapor, and N_2 are brought back into the combustion zone to lower furnace temperatures appreciably, the SO_3 levels in the flue gas will drop, and not enough oxygen will be available beneath slag deposits to convert SO_2 to SO_3 in the required amounts. Similarly, not enough SO_3 will be present to form the alkali pyrosulfates even at low-metal temperatures.

The main problem with flue-gas recirculation is that it may affect combustion conditions unfavorably so that unburned particles of pulverized coal and unoxidized particles of pyrites might reach the wall tubes. As shown earlier, this could cause serious wastage by the sulfide route.

A major effort must be made, then, in planning tests of flue-gas recirculation, to assure that no unburned particles of coal and pyrites impinge on wall tubes. Care must be taken in designing burners to assure a blanket of secondary air along the walls and to prevent any flame impingement. Good pulverization must be obtained, and coal splitters between the pulverizers and the burners must be carefully laid out to assure minimum segregation of coarse coal particles to any one burner. If such preventive steps are taken, flue-gas recirculation should have a minimum impact on corrosion and deposits on wall tubes.

METHODS OF MINIMIZING CORROSION

Two approaches are available in current technology for keeping corrosion to a minimum when combustion modification is used to reduce air pollution. One technique is to improve air-management practices so that the vulnerable areas are not subject to reducing conditions. The other approach is to utilize alloys that are more resistant to attack by the corrosive agents.

Air Management

In the 1940's, when serious wall-tube wastage was first observed, the troubles were blamed on flame impingement; the corrosion patterns closely matched the flame patterns on the wall. As a correctional measure, the operators admitted a part of the secondary air to the casing around the lower section of the furnace so that air infiltrated between the closely spaced tubes to dilute the products of combustion. In other cases, burners were modified to direct a blanket of secondary air along the walls and to minimize flame impingement. These practical solutions essentially eliminated wall-tube wastage by lowering the SO_3 level beneath deposits to the point where the trisulfates could not form.

Air management will be critical in two-stage combustion. The problems of burning pulverized coal with less than the stoichiometric amount of air in the first stage will yield devolatilized "char" to be burned in the second stage, a job that will call for the utmost in air management. And since the problems of sulfide corrosion will be serious if unburned coal particles and unoxidized pyrites reach the furnace walls, great care must be taken to be sure that burner direction, secondary air dampers, and tertiary-air admittance be closely controlled to keep particles away from furnace walls until the second-stage combustion is completed. This is almost certain to call for new concepts in burner design and in furnace geometry.

Industrial boilers, having a relatively high surface-volume ratio, will probably pose greater problems in air management than will large utility-boiler furnaces.

Corrosion-Resistant Alloys

Past experience both with industrial and with utility-boiler furnaces has shown that the selection of alloys for wall tubes and for superheater and reheater elements is based on the oxidation resistance of the alloy and the ability of the alloy to withstand high stress levels. Increased resistance to corrosion beyond normal oxidation has not been justifiable economically. Hence the design philosophy has been to choose the lowest cost alloy that will survive under high stress for 20 to 30 years in an oxidizing environment such as exists in a boiler furnace. For wall tubes this has generally meant a low-carbon steel, and for superheaters and reheaters a low-alloy steel typically containing a small amount of chromium and a little molybdenum. More exotic alloys are either too costly or have undesirable physical characteristics. With the usual levels of excess air in boiler furnaces burning pulverized coal, variations in flue-gas composition have an insignificant effect on the rate of oxidation compared with air.

Decreasing excess air nearly to stoichiometric levels, as is possible with oil firing, has had no essential effect on oxidation since carbon dioxide, water vapor, and nominal amounts of sulfur dioxide are about equivalent to air in forming scale on low-carbon steels at usual working temperatures. Slightly reducing conditions where small amounts of carbon monoxide are present also have little effect on the rate of oxidation, at least when the carbon monoxide level is below 0.1 percent.(18) At higher levels, carbon monoxide can be expected to be troublesome. But since boiler furnaces have not been operated under reducing conditions because this would result in a costly loss of fuel, no data are available on metal wastage problems with boiler furnaces at appreciable levels of carbon monoxide.

High-alloy steels provide greater corrosion resistance than either the carbon or low-alloy steels commonly used. However, as pointed out previously, steels containing substantial amounts of nickel have been subject to sulfide corrosion, which is of particular concern here.

Improvement in the high-temperature corrosion resistance of nickel-base alloys has been reported by Bergman, et al,(19) as a result of addition of rare earth elements to the alloys. Cerium additions in particular were said to provide remarkable benefits when added to nickel-base Udimet 500 alloy in quantities up to 0.5 percent. A possible explanation for this effect is the high melting points of rare earth sulfides and their very high free energies of formation, which would render them good sulfide getters.

Llewelyn has demonstrated that aluminum coatings confer improved sulfide corrosion resistance to nickel-base alloys.(20) Table 1 reproduced from Llewelyn's paper compares corrosion resistance of several alloys with and without aluminum coatings. The table also compares the effects of reducing and nonreducing environments on the corrosion resistance. The data summarized in the table denote the temperature at which attack was first observed on the specimens. Sulfide corrosion began in some of the alloys at temperatures as low as 770 C, while others resisted corrosion up to 980 C. The pack-aluminizing treatment which consisted of hot-soaking a specimen with a mixture of metallic aluminum, aluminum oxide, and ammonium bromide provided a significant increase in the threshold temperature at which corrosive attack began. Increases as high as 170 degrees C were noted for some of the alloys. As recorded in the table, if the material was in contact with carbon its corrosion resistance was somewhat reduced. The aluminizing process also gave significant increases in corrosion resistance in this case as well.

Studies made at the International Nickel Company Laboratories showed that metals of the type discussed by Bergman and Llewelyn, 60 chromium-40 nickel and 50 chromium-50 nickel, may cost three to four times as much as austenitic stainless steels presently used in high-temperature applications but their resistance to corrosion is 4 to 15 times as great.(21)

TABLE B-1. COMPARATIVE RESISTANCE OF VARIOUS ALLOYS COATED AND UNCOATED, TO SULFUR ATTACK

6 HOUR CYCLE, INTERMITTENT SO_2 AND AIR AT 45 MINUTE INTERVALS

MATERIAL IN GAS STREAM	THRESHOLD TEMP °C	MATERIAL IN CONTACT WITH CARBON
	770	M 21 VC
	780	N 105 N100 EPK 24 (IN 100)
M 21 VC	790	
N 105 N 100 EPK 24 (IN 100)	800	
	810	
	820	
G 64 (HT DENUDED LAYER REMOVED)	830	INCO 713 G 64
INCO 713	840	
G 64	850	
	860	
	870	MAR M 200
	880	MAR M 302
MAR M 200	890	N 115
MAR M 302	900	
	910	G 64 (PA Ni_3Al COATING) 500 HOURS 900°C
	920	N 90 X 40
N 90 N 115	930	MAR M 509 MAR M 322
G64 (PA Ni_3 Al COATING) 500 HOURS 900°C	940	
MAR M 322 MAR M 509	950	WI 52 M 21 VC PA
	960	G 64 PA
M 21 VC PA	970	MAR M 322 PA
WI 52 G 64 PA X 40	980	X 40 PA WI 52 PA
	990	MAR M 302 PA
INCO 713 PA N 105 PA X40 PA ERK 24 (IN 100) PA	1000	N 105 PA EPK 24 PA N 90 PA
WI 52 PA	1010	
N 90 PA	1020	MAR M 509 PA
	1030	
	1040	MAR M 200 PA
MAR M 302 PA MAR M 509 PA	1050	
MAR M 200 PA	1060	

PA = PACK ALUMINISED BY BRISTOL SIDDELEY PROCESS

These recent developments in corrosion-resistant alloys and surface treatments to increase resistance to sulfide attack indicate that materials are available to meet the problems that would be anticipated from combustion modification. However, these are very expensive materials to use on a large scale, and research is needed to provide solutions that would be less costly. Further since field assembly of boilers calls for considerable welding, any treatment such as aluminizing would have to be applicable in the field after all welding was completed. Shop assembled panels of wall tube would minimize this problem during construction, but maintenance of wall tubes which occasionally calls for replacing individual wall tubes will call for field welding. Hence any protective coating, or indeed any superalloy, would have to be such as to permit servicing in the field.

RESEARCH NEEDS

The corrosion and deposits problems that may arise from combustion modification cannot be solved without some additional research. The application of air-management principles to protect vulnerable areas in the boiler will require individual attention to each situation in existing boilers. In addition, the design of future boilers should take into account the need for application of these principles.

Research to determine the seriousness of corrosion that can result from staged combustion is particularly important. Some of this work can be done in existing furnaces by the use of corrosion probes. However, laboratory-scale research also is needed to determine whether or not the mechanisms that have been hypothesized for such cases as alternate oxidation and reduction are valid. Applied research to make possible widespread use of low-excess air in pulverized-coal firing is needed especially.

TVA Program

The Tennessee Valley Authority presently is planning large-scale tests of staged combustion in a 125-MW-pulverized-coal unit. To anticipate any possible problems with wall tubes, TVA plans to use a corrosion probe that can be removed periodically to check on metal wastage or the accumulation of potentially damaging deposits in the furnace.(22) To insure that the corrosion probe specimens will have the same radiative and convective heat transfer, gas velocity and direction, and impingement of solid particles that will occur on furnace-wall tubes, TVA is planning to use a probe designed to lie flush with furnace-wall tubes, thus nearly duplicating the conditions on the original furnace wall.

Low-Excess Air in Pulverized-Coal Firing

In order to make the benefits of low-excess air available to pulverized-coal firing, a large-scale research program would be required. An adequate program should investigate the following aspects of the problem especially with respect to low-excess-air conditions:

1. The optimum coal-particle size to provide the necessary surface area for complete combustion
2. Means of proportioning of coal and air at the burner to insure good combustion
3. The possible advantage of corner-firing in providing optimum combustion
4. The design of burners to provide optimum turbulence and rate of mixing in the flame zone
5. The nature of the devolatized char formed in burning different ranks of coal under low-excess-air conditions.

Corrosion Mechanisms

An investigation of the mechanism by which a reducing atmosphere may cause corrosion under boiler furnace conditions is warranted. The questions raised by the European steam-generating incinerator experience have not been answered definitively, although logical mechanisms have been deduced. The effects of alternate oxidizing and reducing conditions with and without flame impingement need to be studied, to ascertain whether chemical attack is involved, or only physical affects such as spalling of deposits to expose fresh surfaces.

Some further study of the extent of sulfide attack under fuel-rich conditions also should be made. The previous data were obtained mostly under oxidizing conditions where poor fuel handling was responsible for the unburned fuel, rather than a truly oxygen-deficient atmosphere.

Corrosion Probe Design

A major problem in the past in controlling corrosion in large boiler furnaces has been the operator's inability to determine loss of metal except from measurements made during major outages. A further difficulty arises in that samples taken from corrosion areas are composites of chemical reactions that have taken place over long periods under varying operating conditions. It is not possible, for instance, in examining badly corroded tubes to attribute the wastage to a single short-lived episode or to continuous low-rate corrosion over a long time. Also, momentary overheating occurring at any time between inspections at outages can radically modify the nature of the overlying deposit, thereby negating its usefulness in explaining the mechanism of corrosion. In short, relying on infrequent inspections of wastage areas is an unsatisfactory way of understanding and explaining corrosion and deposition processes.

Probes have been devised in the past for measuring rates of corrosion and of accumulation of deposits, but serious shortcomings have greatly limited their usefulness. Two major requirements must be met: (1) temperature, rate of heat transfer, and gas velocity and composition over the probe must be identical with conditions on furnace elements; and (2) the probe must be readily removable from the furnace for inspection and as easily replaced for further exposure. No probe used as yet in boiler furnaces has met all these requirements, which can be met only by designing a probe that lies flush with wall tubes or parallel to superheater elements without disturbing existing gas-flow patterns. A probe of this type, proposed by the Battelle Columbus Laboratories, is being considered by TVA for use in their program.

Considerable importance is attached to designing a probe since only with such a device can bad conditions within a boiler furnace be detected before they have caused serious damage to the installation. Also, such a probe will allow evaluation of protective measures without the long delays inherent in field inspection of furnace-wall tubes and superheaters.

Chrome-ore Packing

An investigation should be made of the possibility of utilizing a chrome-ore packing as a method of combating sulfide corrosion under reducing conditions. This approach would entail studding of the boiler tubes and packing chrome ore in the studded area.

This method of preventing corrosion was attempted years ago in oxidizing furnace atmospheres, but was not successful. The chrome-ore oxidized and crumbled away in about a six-month period. However, a recent reference to experience in chemical recovery furnaces used in the Kraft paper industry indicates that under reducing conditions the chrome-ore packing does not deteriorate and protects against sulfide corrosion.(23) In these furnaces the black liquor from the Kraft process is burned and the inorganic chemicals are recovered for recycling in the process. The bottom of the furnace is subjected to a molten mixture of Na_2CO_3 and Na_2S in a reducing atmosphere. In this environment the chrome-ore packing is reported to persist and protect against corrosion. The possibility of using this technique to counteract sulfide corrosion that might occur with two-stage combustion warrants investigation.

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PART C

FLAME STABILITY AS AFFECTED BY COMBUSTION MODIFICATIONS

by

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March, 1974

PART C

FLAME STABILITY AS AFFECTED BY COMBUSTION MODIFICATIONS

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PART C

FLAME STABILITY AS AFFECTED BY COMBUSTION MODIFICATIONS

by

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OVERVIEW

Utilizing various combustion modification techniques to control NO_x emissions from industrial boilers can lead to severe flame stability problems. Because flame stability is directly related to the basic fuel parameters of burning velocity and critical velocity gradient, a change in fuel composition at some point in the combustion system or a change in the burner can alter these parameters and affect the stability of a burner-furnace system. The flame stability criteria of a burner-furnace system must not only be considered in traditional terms of flash-back, blow-off, and quenching potential, but also in terms of the potential for the system to generate combustion-induced noise.

The control of NO_x through combustion modification is a relatively new development and can impose some requirements seemingly opposed to those necessary to satisfy operational demands of a boiler-furnace system(1). These modifications include, low excess air, steam/water injection, flue-gas recirculation, two-stage combustion, biased firing, flame type changes induced by burner swirl, and mixing rate changes produced by burner design changes(2). Because flame stability is related to basic fuel parameters of burning velocity and critical velocity gradient, the degree of applicability of each of these methods will depend on the type of fuel being fired. In addition, it has been shown that the minimization procedures for thermal NO_x are not the same as for the fuel NO_x. The combustion engineer must consider all these factors in the designing of systems to meet acceptable NO_x levels while not causing significant deterioration of boiler performance.

This part of the report is intended to provide not only specific techniques for suppressing flame instability and combustion-induced noise in an industrial boiler system, but also background material describing basic flame instability and noise generating phenomena. Even if the phenomena of flame instability in a modified boiler system were fully understood, which is not the case, that understanding would not be sufficient for the designer.* The designer must blend the basic principles presented in this report with his own ingenuity in achieving the best boiler system design for a particular application.

Because the discussion of flame stability and combustion-induced noise is necessarily complex, a summary of the conclusions is given first, followed by suggestions of future work. Next flame stability is considered in a very broad sense. Not only are the changes in blow-off, flash-back, and quenching potential of a design considered, but also the change in potential for producing combustion-induced noise and combustion-driven oscillations.

Significance of Basic Phenomena Relative to Combustion Modification

From the discussion of flame stability and combustion noise that will follow, several general conclusions can be drawn as to the effect combustion modification has on stability and noise. Because there are voids in present technology and because these basic phenomena are often unique only to specific systems, only general statements can be made. These include

1. Recirculation without excessive cooling of the recirculated gases can actually increase the maximum firing rate (excluding the effect of increased pressure drop through heat exchangers) through increases in the critical velocity gradients. Excess cooling will decrease the maximum firing rate. Design changes for pollution control will probably fall in the "excess cooling" category.

---

* In general, design application of combustion fundamentals is still an art. Current mathematical models of combustion systems are still not sufficiently flexible to permit detailed "computer design".

2. Two-stage combustion can either increase or decrease burner operating range because the effect depends on the details of the burner-furnace system. As a retrofit, decreases result.

3. Steam or water injection will decrease the stability limits.

4. Conversion of combustion systems to use of two-stage combustion, recirculation, and other features for pollutant reduction can be expected to produce the normal incidence of combustion-driven oscillations, because it is common in the development of any new burner-furnace system to encounter these problems. Because of the short time factor involved, and the large number of conversions of existing units and changes to new designs, this problem will be amplified.

5. Changes in design which lower the stability limits will tend to produce an increased incidence of combustion-driven oscillations, and, near the rated firing condition, an increased intensity of combustion roar unless the unit is derated.

6. Recirculation (with cooled products) and steam addition will decrease the mass burning velocity and the expansion ratio between burned and unburned mixture. Provided that the operating range is well within the stability limits (cf items 3 and 5), both of these effects will tend to decrease the noise output, perhaps by a significant amount,* but experimental confirmation is not presently available.

7. Two-stage combustion can be expected to increase the combustion roar and the propensity for combustion-driven oscillations. As a retrofit there will also be a tendency for unstable fluid dynamic phenomena to occur. In the case of biased combustion, careful examination of the details of the system might permit a statement to be made relative to combustion roar but not combustion-driven oscillations,on the basis of present technology.

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* Assuming 25 percent addition of recirculated products which have cooled halfway to ambient temperature, the temperature of the mixture may be about 480 K as compared to 660 K without loss of heat. Using Figure C-4 to determine the burning velocity ratio, correcting the velocity of sound (note that this factor has not been examined experimentally or theoretically), and correcting for the higher intensity of turbulence from the higher flow rate, the efficiency of noise conversion drops to 0.254 of the original value and the sound-power level drops by 6 dB.

Research Needs

This study points to the following research needs relative to flame stability and combustion noise in industrial boilers as affected by combustion modifications:

1. The excellent correlation of burning velocity data and flash-back data on stoichiometric mixtures of three fuels over a wide range of simulated recirculation ratios and temperatures, using the product temperature control theory, suggests that this concept is worthy of (a) deeper examination from a theoretical standpoint, (b) application to a wide range of mixture ratios and fuels using pertinent data in the literature, and (c) experimental confirmation with fuel-recirculated product mixtures in industrial burners, using industrially pertinent fuels.

2. The most common type of excessive noise from a furnace, after the combustion-driven oscillation problems have been handled, is that resulting from approach to flame blow-off. Thus, there is a need for studying the stability limits of industrial-type burners, as contrasted to simple laboratory burners, from both the burner capacity standpoint and the noise standpoint. An understanding of the stability limits of typical industrial burners would aid considerably in predicting problems and designing around problems associated with combustion modification.

3. The following discussion shows that the details of noise production by a turbulent flame are not fully understood. The semiqualitative arguments used to derive correlating relations contain several terms not supported by experimental data or rigorous theory. In particular, the relation used to predict the effects of recirculated products is open to some question. A combined experimental and theoretical study would appear to be indicated.

FLAME STABILITY

General Description

Generally speaking, there are three aspects of flame stability to be considered; blow-off, flash-back, and extinction or quenching. Figure C-1(3) shows how these are related for a Bunsen-type burner on a dimensionless plot of the ratio of flow velocity to burning velocity (V/F) as a function of the Peclet number based on burning velocity and burner diameter (FD/D_t).* This may be compared with the more usual dimensional stability plot of Figure C-2(4) which requires one plot for each burner size, fuel, and pressure.

Laminar Flame Stability

Considering a point on Figure C-1 (at about 60, 1.0), it is seen that an increase in flow velocity or decrease in burning velocity will cause the flame to blow off. A modification of the flow conditions, such as by an electric field, can delay this blow-off. A decrease in flow velocity will cause the flame to flash back upstream. As shown in this figure, an increase in thermal diffusivity, D_t, say, by a decrease in pressure, will result in extinction of the flame from thermal losses.

A constant Reynolds number curve of about 2000 has been added to Figure C-1. The curve has a 45° slope moving downward to the right. Up to this critical Reynolds number, the slopes of the blow-off and flash-back velocity gradient are constant (except near extinctions). On passing through the transition Reynolds number, the flame becomes turbulent. The blow-off and flash-back curves jog and change slope, but the overall picture remains the same. For other types of burners, such as ducts with axially symmetric central bodies (see below), or two-dimensional systems, the same general characteristics hold. Finally, if the flame is a diffusion flame rather than a premixed flame, these relations can be used if the composition is defined in the flame-holding region.

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* V = critical velocity, F = laminar burning velocity,
D = diameter, D_t = thermal diffusivity.

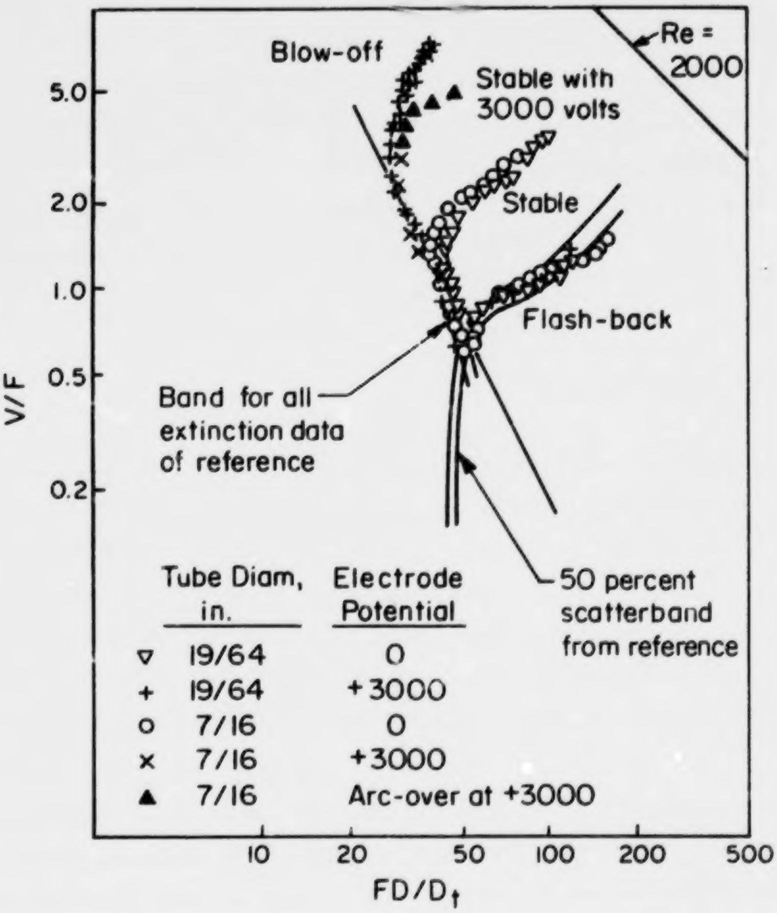

FIGURE C-1. FLASH-BACK, EXTINCTION, AND BLOW-OFF CURVES WITH AND WITHOUT 3000-v FIELD

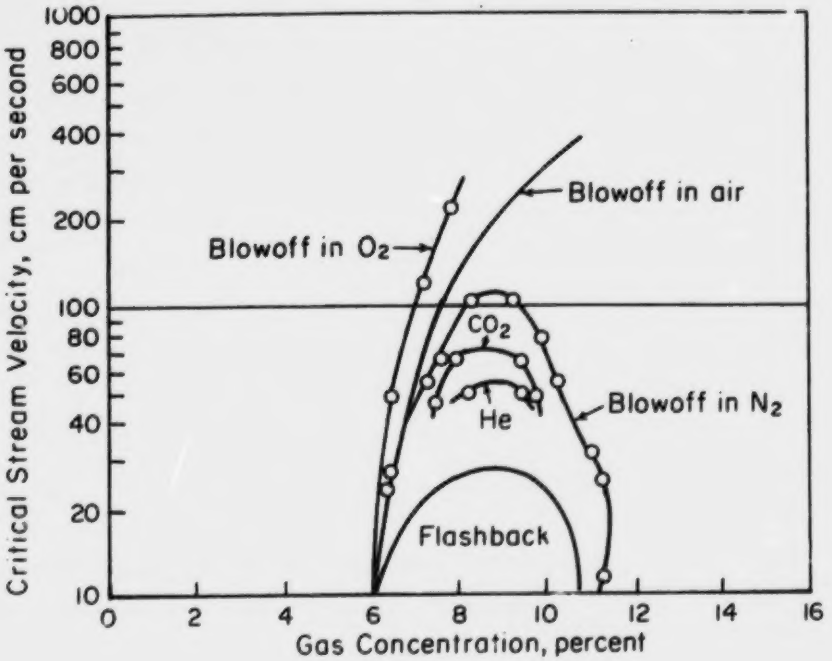

FIGURE C-2. EFFECT OF NATURE OF SURROUNDING ATMOSPHERE ON BLOWOFF OF NATURAL GAS-AIR FLAMES; TUBE DIAMETER, 0.577 cm.

Stability of Turbulent Premix Flame

For turbulent premix flames, Spalding and Tall(5) showed that the blow-off limits of simple axially symmetric flame holders in a premixed stream gave a relation of the form $V/F \approx DF/D_t$ for Reynolds numbers above about 15,000. This can be presented in the alternative form, $V/D \approx F^2/D_t$. For Reynolds number below 15,000, the relation was $V/F \approx (DF/D_t)^{0.4}$. This relation can be, and was explained, on the basis that the size of the recirculation region downstream of the flame holder relative to the flame-holder diameter decreased with increasing Reynolds numbers up to a certain point; it was this size of recirculation region rather than the flame-holder diameter that was the important dimension to stability. Using the critical flow dimension, L, related to the size of the recirculation regions rather than diameter, a velocity gradient term, V/L, becomes the significant aerodynamic variable, proportional to the fuel-air property (F^2/D_t) at blow-off.

Stability of Turbulent Diffusion Flame

In the case of turbulent diffusion flames, the stability phenomenon is more complex than for turbulent premix flames. Generally speaking, the flame will be stabilized near the region where a stoichiometric condition exists, that is, near a maximum burning velocity and minimum flame thickness condition. When the stabilized region is relatively fixed, the interaction of the (mass, momentum, and thermal) diffusion relations is such that the velocity gradient criterion is still highly successful for predicting blow-off in the nonturbulent region.(4) For turbulent conditions, and free floating flames, the results are more complex, but the combustion characteristics of burning velocity and flash-back velocity gradient should still be adequate for comparison purposes.

In the case of liquid fuels, there are two situations that arise. First, when obstacles are present as flame holders, the liquid droplets follow trajectories that tend to cause impingement. Thus the obstacles become wet. Depending on its temperature, the fuel may shear off either as droplets or as vapor. In any case, in the recirculation zone, behind the obstacle, the composition is not necessarily that of the oncoming stream. Thus the stability of the flame in the recirculation zone must be interpreted on the basis of the vapor-air mixture in the recirculating zone and immediate vicinity, and not on an average basis. A similar argument has to be used in the case of the flame spreading from the piloting recirculation zone.

If there is no obstacle-induced recirculation zone for piloting the flame, then the fine drop vaporization and mixing of the fuel with air has to be considered. It might be noted that at atmospheric temperature, droplets of the order of 5 micron or less result in flames generally similar to that of a vapor. On this basis, the observed stability phenomena can be related to those observed with a premixed gaseous fuel.

Basic Stability Parameters

Only a small number of fundamental properties of combustible mixtures are required to correlate experimental data when dimensionless relations are used. In fact, for considering the physical properties (rather than chemical properties) of flames, two parameters appear to be sufficient, the laminar burning velocity and the laminar flame thickness. The laminar burning velocity has been identified as significant in Figure C-1. However, in the horizontal coordinate, the dimensionless parameter should have been D/δ, rather than FD/D_t, where δ is a suitably defined laminar flame thickness.* The substitution stems from the lack of data on laminar flame thickness; because of this, the approximate relation that $F\delta/D_t$ is a constant is used to eliminate δ.(7) It might be noted that some investigators prefer to use D_v, a mean molecular diffusivity, rather than D_t, the thermal diffusivity. But while this is important in considering the kinetic details of combustion, the difference is not significant to this discussion.

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* There are several ways to define flame thickness.(6) The various thicknesses are related by (hopefully) constant factors.

A third parameter, more convenient to obtain than δ, is the ratio, F/δ . This ratio can be considered a chemically controlled reaction rate per unit volume. It is also proportional to the velocity gradient at flash-back for a Bunsen-type burner and, in premixed turbulent flames from flameholders, to blow-off velocity gradient. Extensive tabulations of these values for various fuel gases are available in Bureau of Mines RI 5225.* (4)

It follows that the predictions of the effect of various changes in burners and burner systems made to control pollution can be based on the changes that occur in these basic flame properties, plus a knowledge of the accompanying dimensional and velocity changes. Therefore, the effects of recirculated products on burning velocity and flash-back velocity gradient will be considered before proceeding to some examples of the effects expected in burner performance from changes made to suppress pollution.

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* It should be noted that Grumer, et al.,(4) presented extensive sets of data on the stability limits of various hydrocarbons, hydrogen, and carbon monoxide with air. These cover a wide range of mixture ratios for each fuel. Furthermore, rules are formulated for computing the limits for mixed fuels, and notice is given of combinations that do not follow these rules. However, using data on strategically chosen mixtures as the starting point rather than pure fuels, the simple rule can be extended to the problem cases with some degree of success.

Burning Velocity

To evaluate the various types of changes that might be made in a combustion system to reduce pollution, changes in burning velocity as a result of (a) changes in mixture ratio, (b) changes in temperature, (c) addition of recirculated products, and (d) addition of steam or water must be considered. Since the performance of most hydrocarbon fuels are similar (except for stability of a laminar flame front in certain special cases wherein the relative molecular diffusivities of fuel and oxygen became important), general conclusions can be based in most instances on consideration of data on any of the hydrocarbon fuels.

Figure C-3(8) shows the burning velocity of several hydrocarbon-air flames, obtained using the angle of the inner cone of the flame above an accelerating nozzle, as detected by a modified Schlieren method. It is noted that the curves are all much the same shape, with peaks that are slightly on the fuel-rich side of stoichiometric (90 percent to 95 percent stoichiometric air). Not shown in this figure are ethylene, peaking at about 0.70 meter/sec, and hydrogen, at 2.80 meter/sec. Mixtures of hydrocarbon fuels are essentially linear in respect to burning velocity. However, hydrogen additions do not have a linear effect, and CO addition is even more confusing in its effect.(9) Nevertheless, the general burning velocity curves are the same shape, and conclusions may be drawn on the basis of any of the fuels.

Derivation of Basic Relation. Karr and Putnam,(10) from a study of available data, suggested that the addition of recirculated products without loss of heat to a premix burner does not change the flame shape. In other words, the addition of the products can be ignored in this special case. A theoretical argument based on the Brokaw-Gerstein(11) formulation of the SZFK equation for burning velocity led to the same conclusion.

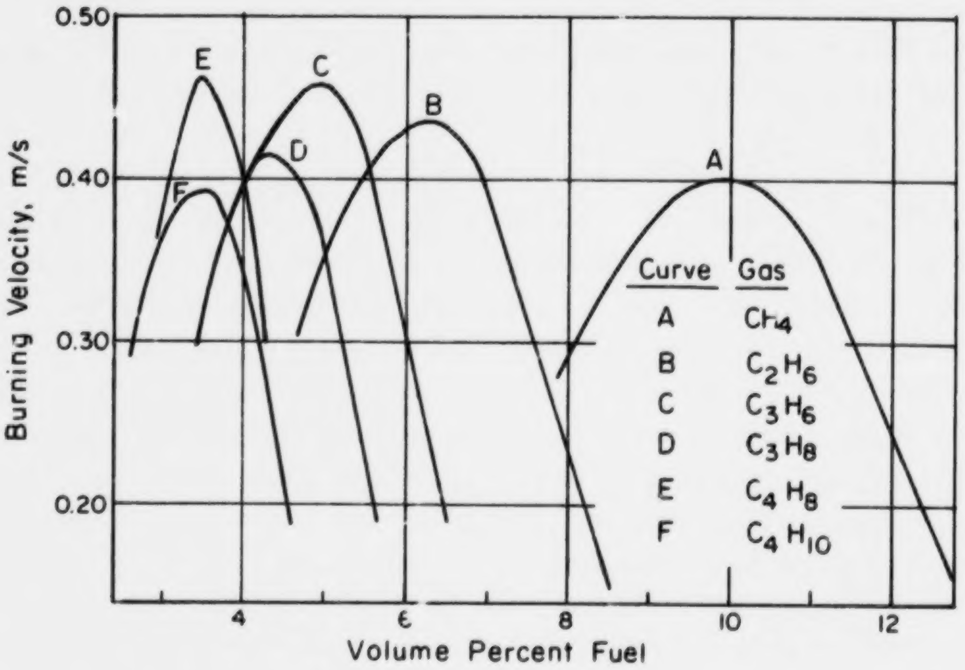


FIGURE C-3. BURNING VELOCITIES OF ETHANE, PROPYLENE, PROPANE, n-BUTYLENE-1 and n-BUTANE WITH AIR

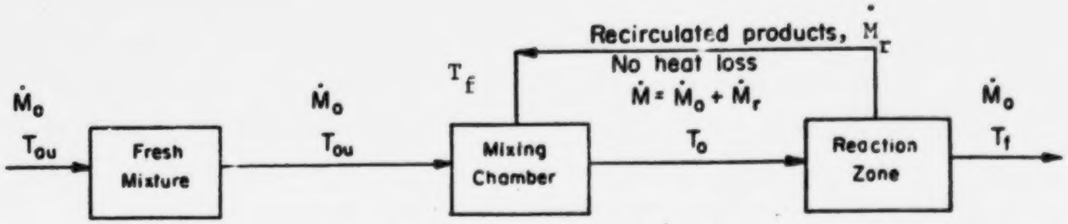
Following this line of reasoning, the effect of the addition of cooled products of combustion can be determined on the basis of the effect of the addition on the peak flame temperature, and the effect of peak flame temperature on burning velocity for undiluted mixtures. Furthermore, if products from the burning of one mixture are added to a mixture of another composition, the effect can be determined by considering the final temperature and composition. This follows because the theoretical arguments that appear to give predictions compatible with the data are based on the *assumption of a controlling influence of the final temperature and composition on the reaction rate*. Again, using the Brokaw-Gerstein formulation, but allowing for the loss of heat from the recirculated production, and assuming a small drop in maximum flame temperature,

$$\ln \left[(F'/F_u) \; (T_{ou}/T_o') \; (\dot{M}_o/\dot{M}) \right] = -(T_o - T_o') \; (E/2RT_f^2) \qquad (1)$$

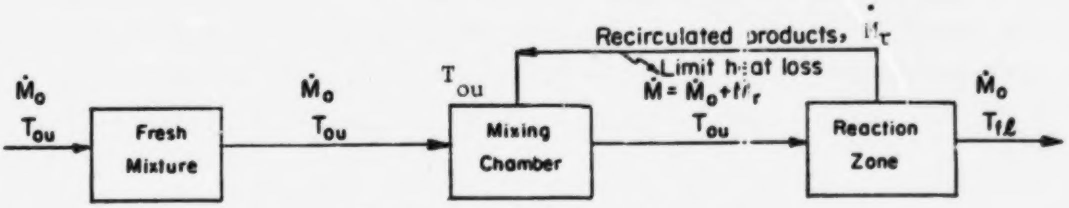
where, using Figure C-4a and c as a basis, T_o is the temperature that the mixture (of recirculated products plus unvitiated fuel-air mixture, with total mass rate $\dot{M}$) would have had without loss of heat from the recirculated products, T_o' is the actual temperature of the mixture, T_{ou} is the temperature of the unvitiated fuel-air mixture of mass rate $\dot{M}_o$, and T_f is the flame temperature of the incooled products. F_u is the reference burning velocity at temperature T_{ou}, and F' is the burning velocity of the vitiated, cooled mixture.

Discussion of Data. Figure C-5 shows the data obtained by Karr and Putnam(10) on the rig of Figure C-4c, plotted in the indicated manner. E was found to be about 40 kcal/mole for the solid curve, which is based on the assumption of a theoretical adiabatic flame temperature plus a temperature invarient specific heat.

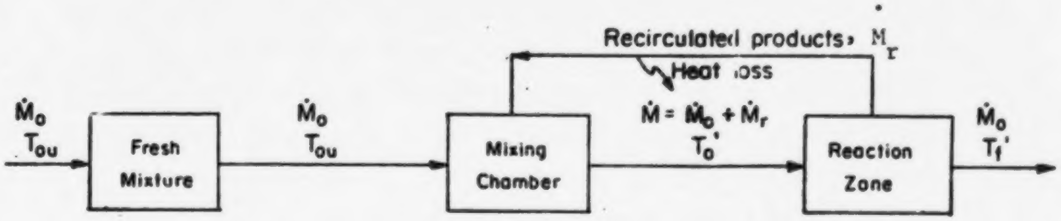
Reed, et al.,(12) studied the effect of vitiation on burning velocity by the use of nitrogen and carbon dioxide, at the ambient temperature. This type of experiment is similar in concept to that of Figure C-4b . For convenience, these diluents were mixed first with the methane, before mixing with the air, so the data are given in the


Recirculated products, $\dot{M}_r$
No heat loss
$\dot{M} = \dot{M}_o + \dot{M}_r$
T_f
$\dot{M}_o$
T_{ou}
Fresh Mixture
$\dot{M}_o$
T_{ou}
Mixing Chamber
T_o
Reaction Zone
$\dot{M}_o$
T_f

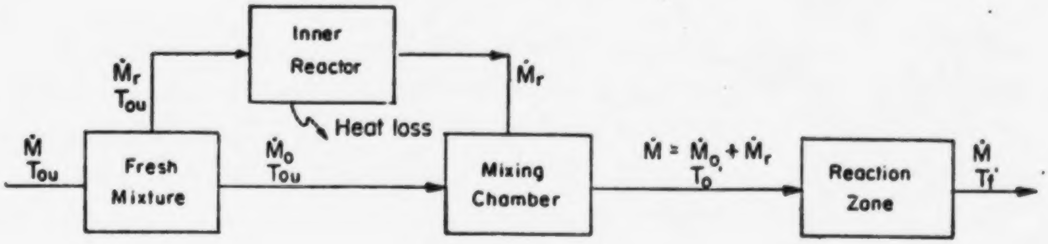
a. Recirculation With No Heat Loss


Recirculated products, $\dot{M}_r$
Limit heat loss
$\dot{M} = \dot{M}_o + \dot{M}_r$
T_{ou}
$\dot{M}_o$
T_{ou}
Fresh Mixture
$\dot{M}_o$
T_{ou}
Mixing Chamber
T_{ou}
Reaction Zone
$\dot{M}_o$
$T_{f\ell}$

b. Recirculated Products at Ambient


Recirculated products, $\dot{M}_r$
Heat loss
$\dot{M}_o$
T_{ou}
Fresh Mixture
$\dot{M}_o$
T_{ou}
Mixing Chamber
$\dot{M} = \dot{M}_o + \dot{M}_r$
T_o'
Reaction Zone
$\dot{M}_o$
T_f'

c. General Case


Inner Reactor
$\dot{M}_r$
T_{ou}
$\dot{M}_r$
Heat loss
$\dot{M}$
T_{ou}
Fresh Mixture
$\dot{M}_o$
T_{ou}
Mixing Chamber
$\dot{M} = \dot{M}_o + \dot{M}_r$
T_o'
Reaction Zone
$\dot{M}$
T_f'

d. Experimental Rig

FIGURE C-4. SCHEMATICS OF FLOW AND TEMPERATURE IN VARIOUS RECIRCULATION SITUATIONS.

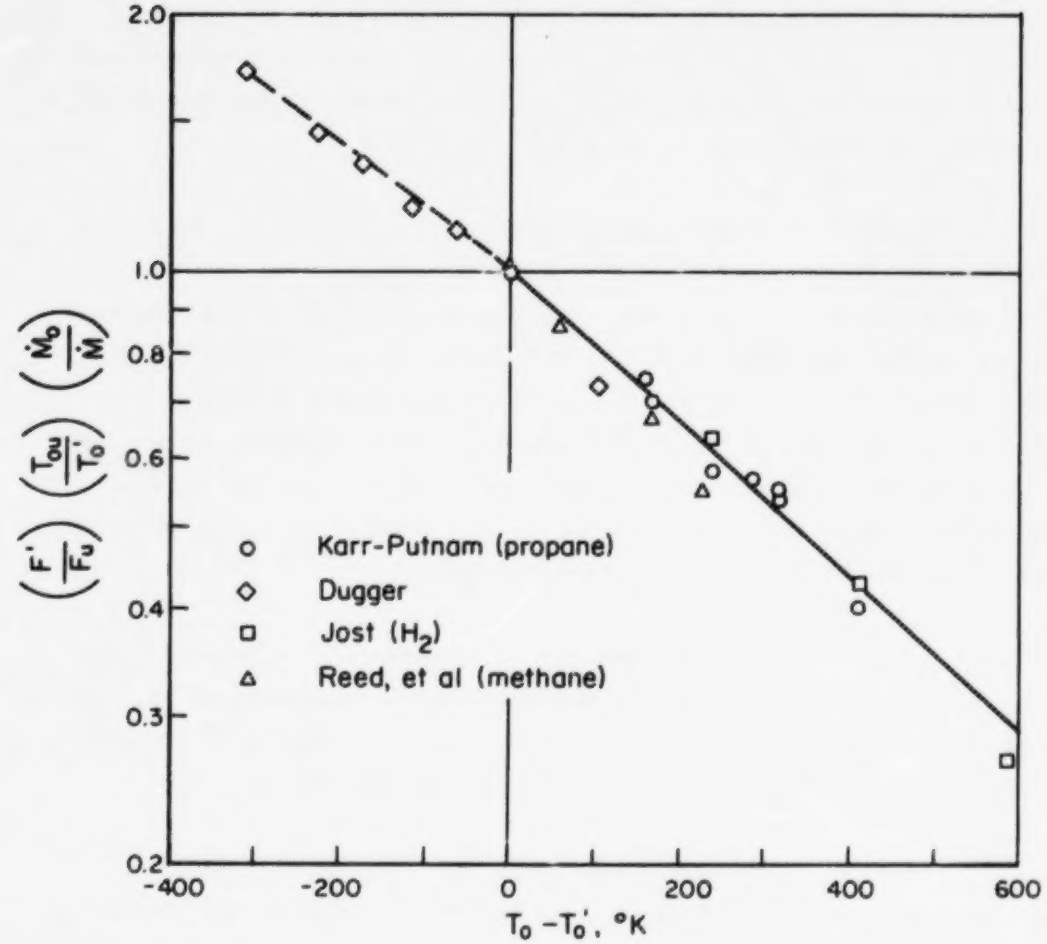


FIGURE C-5. REDUCED BURNING VELOCITY RATIO AS A FUNCTION OF TEMPERATURE DEPRESSION RESULTING FROM HEAT LOSS form of volume ratio of diluent in the fuel-diluent mixture. The burning velocities for each fuel-diluent mixture are plotted against the fuel concentration as a fraction of stoichiometric concentrations, as shown in Figures C-6 and C-7 . Their data replotted on Figure C-5 by use of the relation $T_o - T_o' = (1890\ K)\ (1 - \frac{\dot{M}_o}{\dot{M}})$ show close agreement, especially when considering that the fuel is methane rather than the propane of Figure C-5 , the diluent is nitrogen rather than products of combustion, and the diluent is at ambient temperature rather than near the flame temperature.

Dugger(13) reported data on the effect of initial mixture temperatures on the burning velocity of methane, propane, and ethylene with air. These data can be interpreted in the framework of the recirculated products effect uncovered by Karr and Putnam. Thus, Dugger's data for stoichiometric mixtures of propane and air are added to Figure C-5. Considering the wide variation of flame temperature over the range of data, as compared to the narrow range assumed is the derivative of Equation (1) that leads to a straight line prediction, the slight curvature of the line through the two sets of data is not unexpected.

It can be concluded that the above method of plotting experimental data on a given fuel-air mixture with various amounts of recirculated products added is acceptable for use in predicting the effects of recirculation on burning velocity in practical combustion systems.

Steam or water injection reduces NO_x formation by lowering flame temperature (water vapor in the atmosphere has a similar effect). However, this reduction in flame temperature also reduces the burning velocity as shown in Figure C-8(13) for a saturated mixture of methane and air at 20 C. It might be noted that if Figures C-6, C-7, and C-8 are normalized as far as diluent is concerned on the basis of molar specific heats of the diluents, the effects on burning velocity become essentially the same for all three.

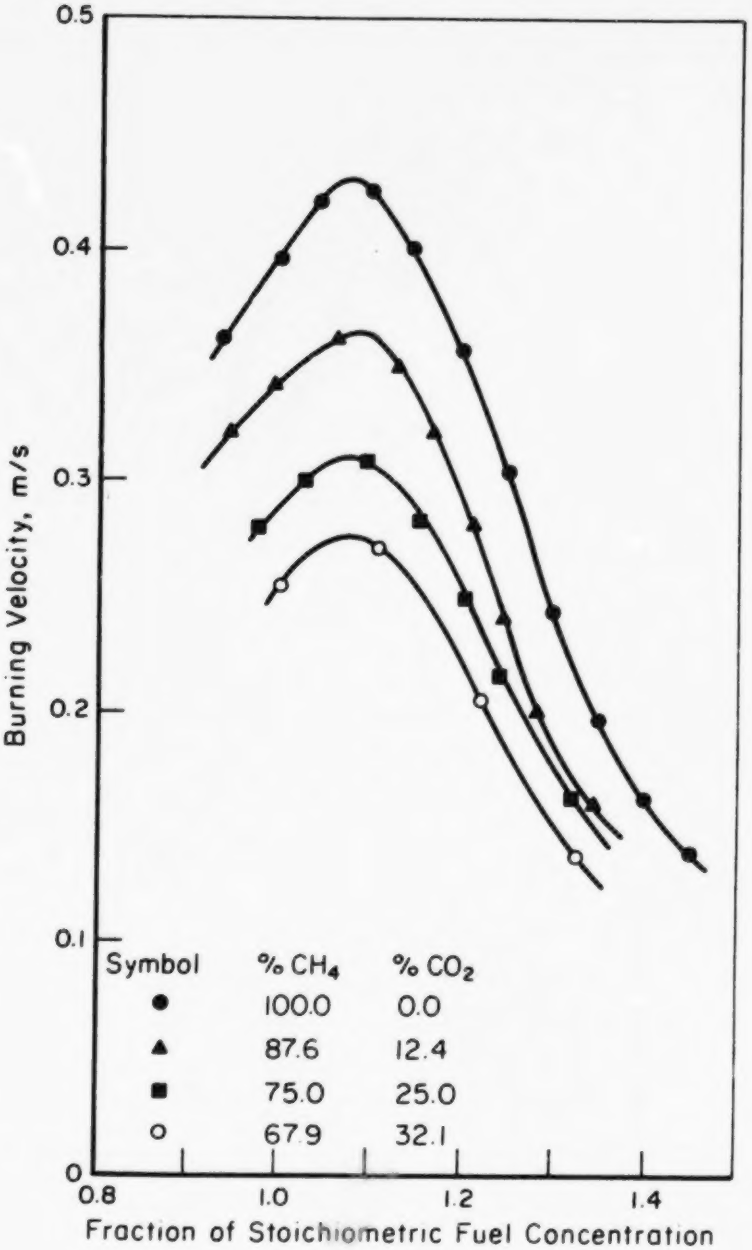


FIGURE C-6. MEASURED BURNING VELOCITIES OF METHANE/CARBON DIOXIDE/AIR MIXTURES

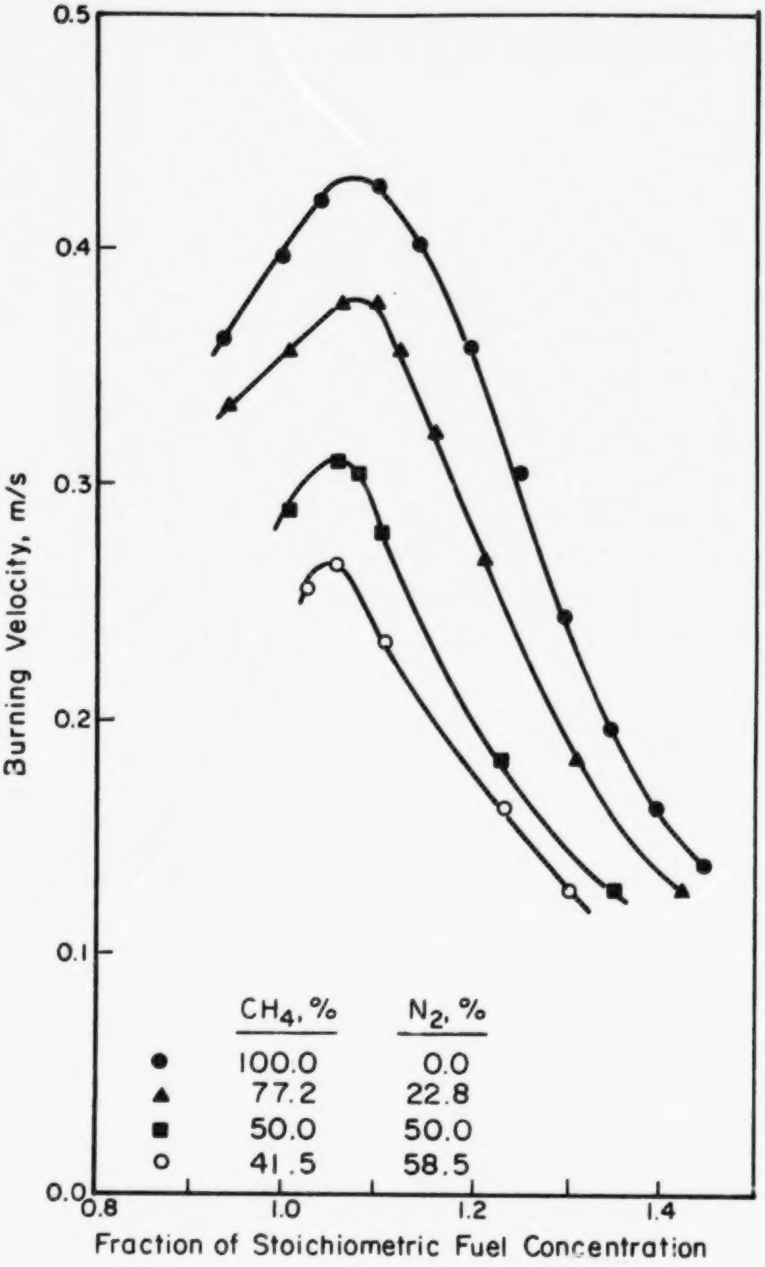


FIGURE C-7. MEASURED BURNING VELOCITIES OF METHANE/NITROGEN/AIR MIXTURES

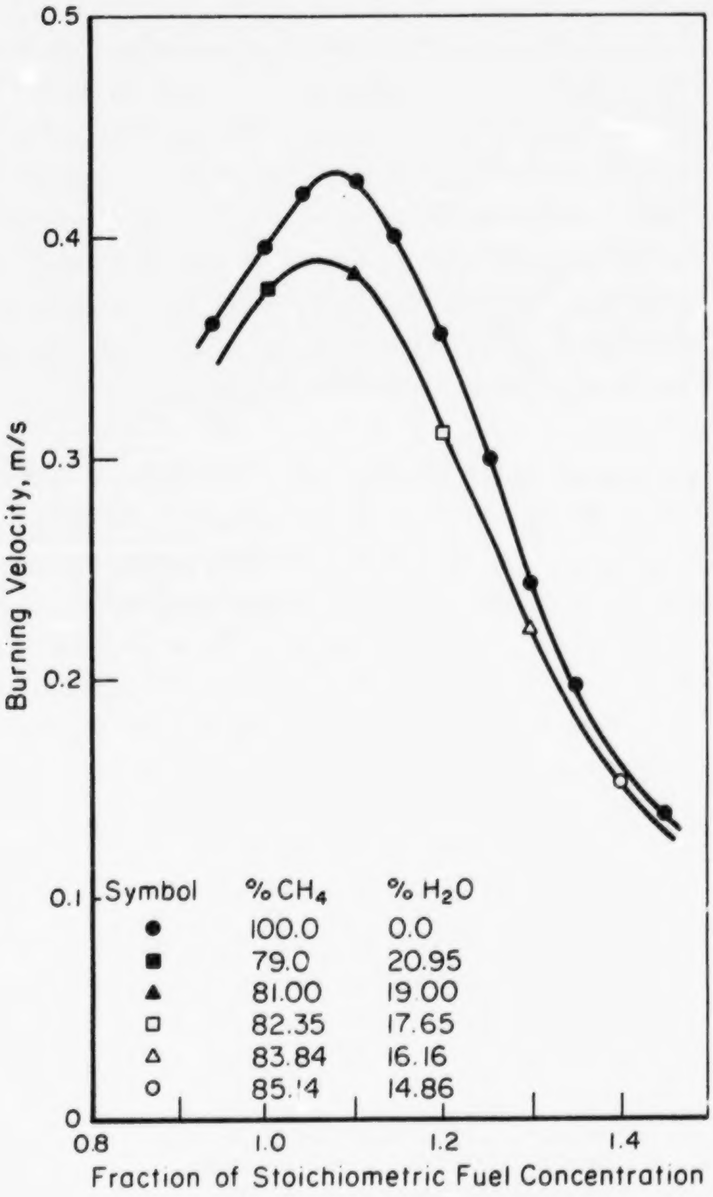


FIGURE C-8. MEASURED BURNING VELOCITIES OF METHANE/AIR MIXTURES SATURATED WITH WATER VAPOR AT 20 C . NOTE THAT PERCENT OF H_2O in CH_4/H_2O MIXTURE VARIES AS THE STOICHIOMETRIC RATIO VARIES

Chemically Controlled Reaction Rate Per Unit Volume

It is noted that the chemically controlled reaction rate per unit volume has the dimensions of reciprocal seconds. Thus, one might suspect that any measured flame phenomena that has a time dimension could be related to the term. Indeed, Giammar and Putnam(14) have suggested that this factor is related to the peak frequency of the turbulent flame noise spectrum. A variety of ignition delay measurements are also in this class. But for the present discussion the flash-back velocity gradient discussed above will be used as the indicating parameter for the chemically controlled reaction rate.

Derivation of Basic Relations. In order to determine a form for predicting the data on chemically controlled reaction rate per unit volume, the *assumption is made that the controlling feature of a flame is the region in which combustion is nearly complete*. On this basis, it is assumed that $F_f\ \delta/D_{tf}$ is a constant.* On the basis of the mixture supply temperature, this became $(F\delta/D_t)\ (T/T_f)^{n-1}$ where n is between 1 and 1.5. The volume reaction rate per unit volume, R_v, on the basis of the supply conditions then becomes $R_v = F/\delta = K\ (F^2/D_t)(T/T_f)^{n-1}$, and the mass reaction rate per unit volume, $R_m = K\ (F^2\rho/D_t)(T/T_f)^{n-1}$. The mass reaction rate of the unvitiated material per unit volume is given by $R_m^* = R_m\ (\dot{M}_o/\dot{M})$. This last rate is quite meaningful since it permits direct comparison at a constant firing rate of fresh mixture before vitiation.

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* We note that the assumption that $F\delta/D_t$ is a constant, where all terms are defined at the fresh mixture temperature, is quite common. This assumption was made in Reference (10) , and led to a slightly different equation than deduced herein.

Making the assumptions consistent with those in Reference (10),

$$\ell n \left(\frac{R_v}{R_{vu}}\right)\left(\frac{\dot{M}_o}{\dot{M}}\right)^2\left(\frac{T_{ou}}{T_o}\right) = -\frac{E}{RT_f^2}\,(T_o - T_o') \,. \tag{2}$$

$$\ell n \left(\frac{R_m}{R_{mo}}\right)\left(\frac{\dot{M}_o}{\dot{M}}\right)^2 = -\frac{E}{RT_f^2}\,(T_o - T_o)\,, \tag{3}$$

and

$$\ell n \left(\frac{R_m^*}{R_{mo}^*}\right)\left(\frac{\dot{M}_o}{\dot{M}}\right) = -\frac{E}{RT_f^2}\,(T_o - T_o)\,. \tag{4}$$

Discussion of Data. Unfortunately there are few data to use in confirming these relations. Reed and Wakefield(15) present some blow-off data on Bunsen-type burners using methane, with a diluent composition simulating the concentration of a burned stoichiometric methane-air mixture. For our purposes, the only easily interpreted data are therefore for the stoichiometric mixture. The mixtures studies were at room temperature, simulating the situation of Figure C-4b. These data were put in the form comparable to Equation (2) by multiplying the stability ratio by $(\dot{M}_o/\dot{M})^2$ and determining $T_o - T_o'$ from $1900\left(\frac{1}{\frac{Q}{Q_r} - 1}\right)$, where Q_r/Q was determined from the percent O_2. We note that $T_{ou}/T_o' = 1$ for these data.

Figure C-9 shows the resulting curve, which turns out to be a straight line with the same slope as that of Figure C-5. This indicates a similar activation energy. While the effect of the temperature term, T_{ou}/T_o' is not confirmed because of the lack of the proper data, it does seem that the agreement with the theoretical prediction as far as pattern of data, and agreement with Figure C-5 are concerned, does give confidence to the proposed equation for prediction changes in critical velocity gradient.

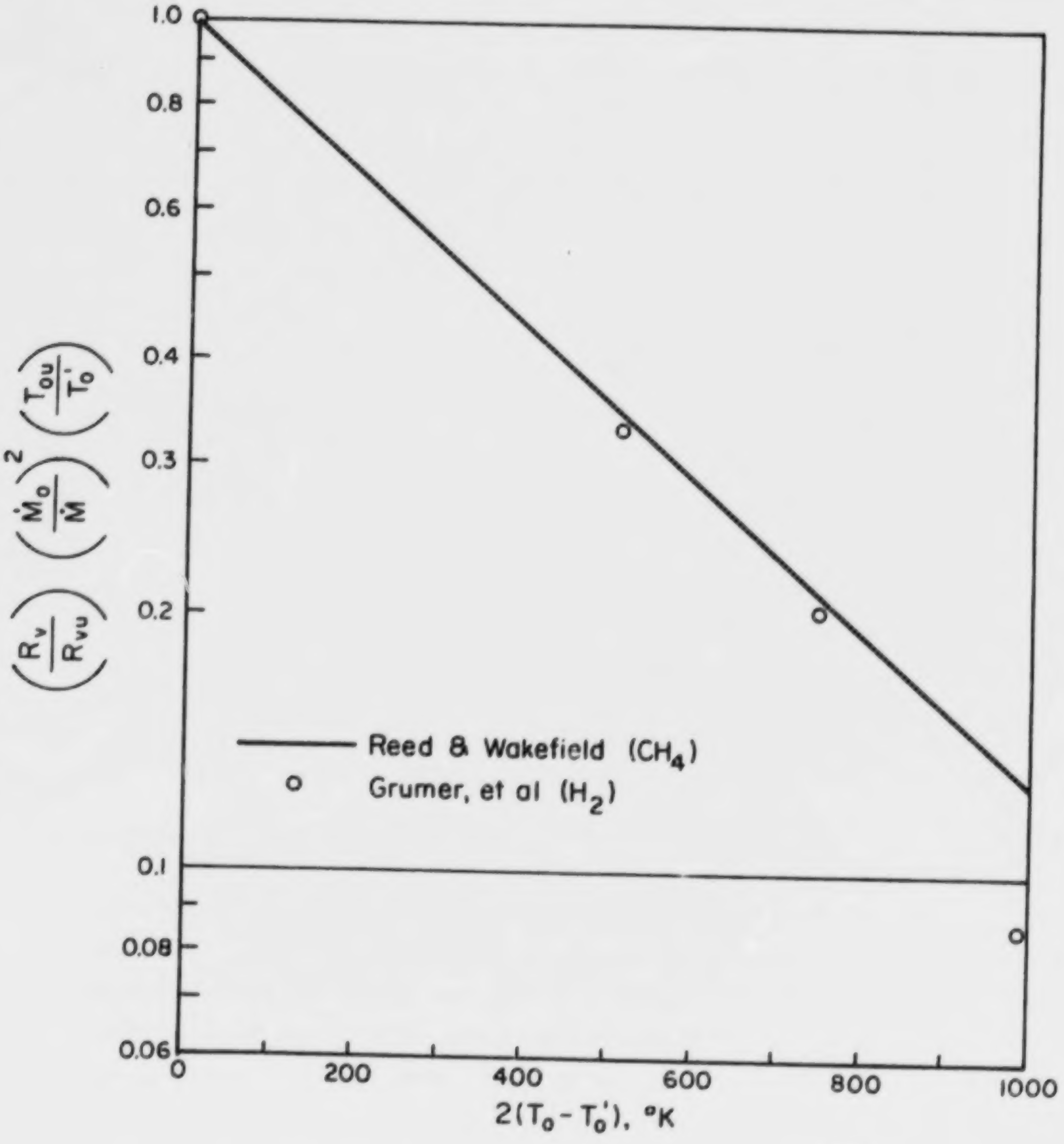

FIGURE C-9. REDUCED CRITICAL VELOCITY GRADIENT AS A FUNCTION OF TEMPERATURE DEPRESSION RESULTING FROM HEAT LOSS

Grumer, et al., obtained data on the flash-back and blow-off methane-air mixtures over a range of temperatures.(4) The flash-back data can be considered in the same light as the burning velocity data of Dugger, in extending the stability curve. The more numerous Bunsen burner type blow-off data on the effect of temperature changes (others have investigated this) is not within the framework of this study because the ambient air (in the reported studies, which enters into the blow-off stability) is not at the experimental temperatures but is at ambient temperature. Thus, the blow-off stability limit at higher temperatures is depressed.

Figure C-10 shows these flash-back data. The curve through the data is from Figure C-5 , obtained from flame speed considerations.

Grumer, et al., suggested that mixtures of fuels may be handled by a linear summation on a volume basis of the flash-back or blow-off gradients assigned to each component. Except, as the authors point out, for large additions of H_2 or CO, this seems to be a satisfactory approach. However, they also suggest assigning to inerts a value of zero in the additive relation. This Bureau of Mines suggestion does not agree with the relation suggested by this study except for one specific mixture of methane and ethane with small amounts of diluent. Therefore, the subject was examined for confirming data. There was one set of stability data for methane with about 10 percent nitrogen but the flash-back showed an anomaly in that the addition of nitrogen increased the flash-back velocity. This is contrary to the prediction of both approaches. The second set of data were for hydrogen-nitrogen mixtures. These data are shown in Figure C-9 with the temperature diffusion normalized by the square of the ratio of flame temperatures. No normalizing change was made relative to the value of E. The agreement is excellent. To inspect the results further, data on burning velocity of nitrogen-diluted air mixed with hydrogen were read from Jost (Figure 90).(16) The reduced burning velocities are plotted in Figure C-5 against the equivalent temperature difference used, normalized to correct for the difference in flame temperatures. Again the agreement is excellent, with the possible exception of the last point.

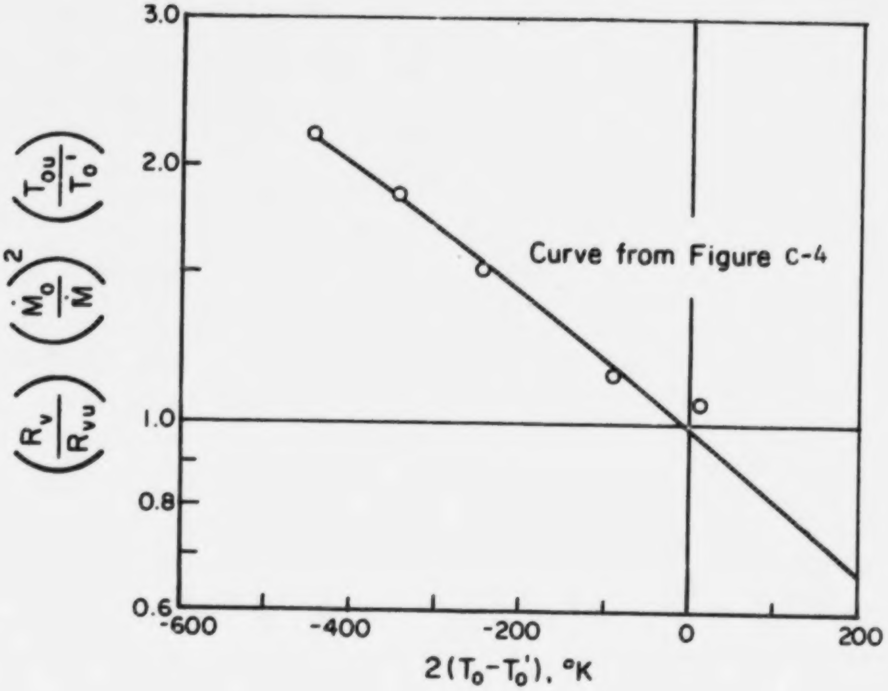

Figure C-10. REDUCED CRITICAL VELOCITY GRADIENT AS A FUNCTION OF TEMPERATURE INCREASE

(Grumer, Harris, and Rowe)

Effect of Design Changes on Stability

In general, the details of a design change to decrease the NO_x production have to be considered before a prediction can be made as to the concurrent effect on burner stability. To illustrate the procedure, two cases are considered herein. In the first, the effect of recirculation of the products of combustion on the maximum firing rate is considered. In the second, the effect of two-stage combustion at a constant firing rate on the proximity of the stability limit is considered. In both instances, the initial configuration is used as a standard.

Recirculation. A discussion on the effect on stability of recirculating the products of combustion into the air supply of an industrial gas-fired burner in a furnace will include the range of cases from recirculation of products of combustion without loss of heat to products with complete cooling to the incoming air temperature. The primary air-fuel ratios will be assumed to remain constant. To carry out the computations, Figure C-9 will be used. The criterion of merit will be the fraction of the undiluted firing rate that is attained at the flame stability limit. Since the size of the burner is assumed constant, the item of interest is given by Equation (4).

$$\ln\left(\frac{R^*_m}{R^*_{mo}}\right)\left(\frac{\dot{M}_o}{\dot{M}}\right) = -\frac{E}{RT_f^{\,2}}(T_o - T_o) \qquad (4a)$$

To determine $T_o - T_{ou}$, we assume as an example a temperature difference, $T_f - T_{ou}$, of 1800 K. As a result

$$1800\left(1 - \frac{\dot{M}_o}{\dot{M}}\right) = T_o - T_{ou}.$$

For no loss of heat from the recirculated products,

$$\frac{R^*_m}{R^*_{mo}} = \frac{\dot{M}}{\dot{M}_o} = 1 + \frac{\dot{M} - \dot{M}_o}{\dot{M}_o}$$

For a loss of heat sufficient to reduce the temperature of recirculated products to the ambient temperature,

$$\ln\left(\frac{R^*_m}{R^*_{m_o}}\right)\left(\frac{\dot{M}_o}{\dot{M}}\right) = -\frac{E}{RT_f^{\,2}} \quad (1800)\left(1 - \frac{\dot{M}_o}{\dot{M}}\right) .$$

Figure C-11 shows the effect of recirculation on the firing rate at the stability limit. It is seen that a small reduction in temperature of the recirculated products can be tolerated with no reduction in firing rate at the stability limit. For moderate reduction in temperatures of the recirculated products, a minimum reduction in firing rate is attained, and further increase in recirculation increases the stability. For larger reductions in temperature, the reduction in stability becomes excessive.

Any specific situation has to be measured also in terms of the concomitant reduction in NO_x and the possible change is pressure drop and performance of the heat exchanger components of a furnace system. The concensus of several discussions $^{(43)}$ is that the retrofitting to use recirculated products will reduce the capacity of present installation, and probably of new designs.

Two-Stage Combustion. One approach to the reduction of NO_x has been the use of two-stage combustion. For furnaces with multiple burners, this may be done in many instances by diverting the fuel from the last set of burners to the previous sets, with a resultant increase in the fuel-air ratio in the initial sets of burners. If there are n sets of burners, the air/fuel ratio relative to stoichiometric, α_1, would then be reduced to

$$\alpha_2 = \alpha_1 \left(1 - \frac{1}{n}\right).^*$$

---

* Dykama$^{(43)}$ points out that, because of the back pressure of the flame, this relation over-estimates the primary combustion air. Because the flame pressure drop varies with flame stabilizing position and thus mixture ratio, fluid dynamic instabilities of an undesirable amplitude can result. Robinson and Cavers $^{(43)}$ list the fuel sensitivity to this problem as P.C. - none, oil - small, and gas - large.

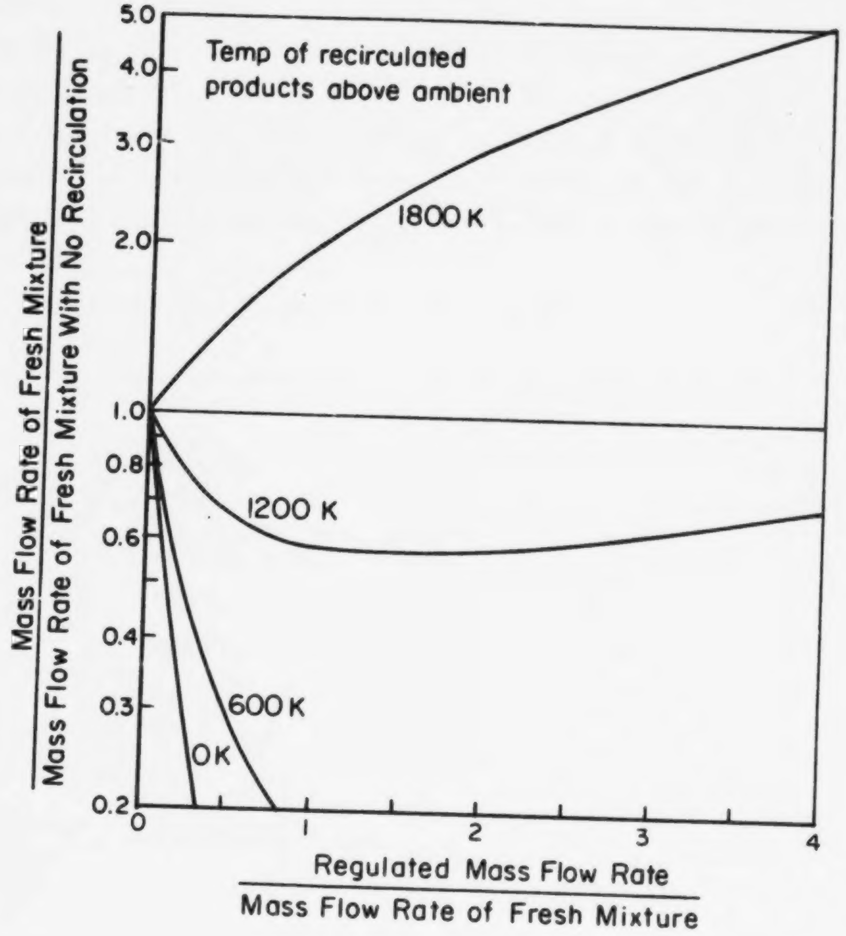

FIGURE C-11. EFFECT OF RECIRCULATION ON MASS FLOW RATE OF FRESH MIXTURE (FIRING RATE) AT STABILITY LIMIT

The effect of this change on the stability limits will be examined as a sample case, for a set of natural gas/air burners, with 120 percent and 110 percent theoretical air before modification. For the illustration, the data of Figure 20 of Reference (4) will be used; the data are for methane with a mass ratio of air to methane at stoichiometric of 17.2.

For the original system, the critical velocity gradient at flashback at 120 percent air (.833 fuel) is 240/sec and at 110 percent air (.909 fuel) is 350/sec. (Note the argument presented previously against using blow-off limit as a measure of chemically controlled reaction rate per unit volume, or stability in closed system). For several different numbers of burner banks, the following table may be produced.

TABLE C-1. EFFECT OF TWO-STAGE COMBUSTION

Number of Burner Banks	$\frac{\text{Air/Fuel}}{\text{Air/Fuel Stoich.}}$	Flash-Back Gradient, $\sec^{-1}$	Mass Flow Rate	Fractional Increase in Stability Limit
		(a) 120% Stoichiometric		
3	0.80	140	1.023	- 0.43
4	0.90	330	1.015	+ 0.35
5	0.96	390	1.012	+ 0.61
6	1.00	390	1.009	+ 0.61
7	1.03	380	1.008	+ 0.57
		(b) 110% Stoichiometric		
4	0.825	180	1.015	- 0.49
5	0.880	300	1.012	- 0.15
6	0.917	350	1.009	- 0.01
7	0.943	380	1.008	+ 0.08

It is clear from a study of these results that the stability of the combustion system as related to its rated firing rate may increase or decrease, depending on the number of burners involved in the system and the overall air/fuel ratio before modification. For the smaller numbers of burner banks, however, the changes cause a deterioration in performance.

For this reason, retrofits based on this principle decrease the furnace capacity, but, in new designs, this need not be the case(43).

COMBUSTION NOISE

Historically, the combustion-system noise of interest was in the high frequency screech and lower frequency pulsations that occasionally emanated from such systems because such noise could be of intolerable level, detrimental to combustor performance, or cause physical deterioration of the equipment. However, both because of the increased realization of the detrimental effects of noise on work output, and the increased attention of various legislative bodies to the problems of industrial noise, the combustion community is now adding to its concern for combustion-driven oscillations the industrial counterpart of the comforting "roaring" fireplace. In addition to (1) combustion-driven oscillations, and (2) combustion roar, at least two other classes of combustion noise must now be considered. These are (3) the unstable combustion noise generated by the precursor of the blow-off conditions of a flame (discussed previously), and (4) the amplified noise of periodic flow phenomena. Each of these classes will be discussed in sufficient detail to transmit a general understanding of the specific class. This will be followed by discussion of the significance of each class relative to design changes that might be made to improve the pollution performance of the existing combustion systems or new systems.

Basic Phenomena

As pointed out above, combustion-driven oscillations are the most widely investigated phenomenon, of the classes combustion-generated noise. Combustion-driven oscillations are characterized by the presence of some sort of feed-back cycle. This is in contrast to the other three types of phenomena that do not have such a feed-back cycle present. However, when combustion-driven oscillations are not strongly generated, they can be confused with the acoustic amplification of specific frequencies in the broad band spectrum produced by combustion roar. Furthermore, when specific frequency generated mechanisms such as vortex shedding are present, these specific aerodynamic frequencies can produce noise that is amplified by the combustion process; this phenomena can also be confused with low amplitude combustion-driven oscillations. Finally, it must be noted that the noise produced by the vortex shedding phenomena (commonly considered to be related to a Strouhal number) is often of about the same intensity and in the same noise spectrum as one obtains from combustion roar; therefore these two sources of noise can be confused.

Combustion-Driven Oscillations

Combustion-driven oscillations, often termed pulsating combustion, in larger pieces of equipment with lower natural frequencies, involve a feed-back cycle that converts chemical energy to oscillatory energy in the gas flow. The noise spectrum ordinarily involves one specific frequency and its harmonics. Figure C-12 shows the noise spectrum* obtained for an extreme case of combustion-driven oscillations, a situation in which the oscillations were purposely generated in a pair of pulse combustors. Figure C-13 shows another example of combustion-driven oscillations, in a large air heater.(17)

Typical efficiencies of conversion of chemical energy to noise are about 10^{-4}, although purposely produced pulsations in pulse combustor can have efficiencies considerably higher.(18) As a result of the high conversion efficiency relative to the other types of combustion generated noise, not only can the noise produced be unbearable, but large changes in combustion efficiency and physical destruction of the equipment can occur. Thus, combustion-driven oscillations have always received attention, both by industry in respect to residential and industrial combustors,

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* The sharpness of the peaks as recorded involves not only the physical characteristics of a pulsation but the characteristics of a recording system.

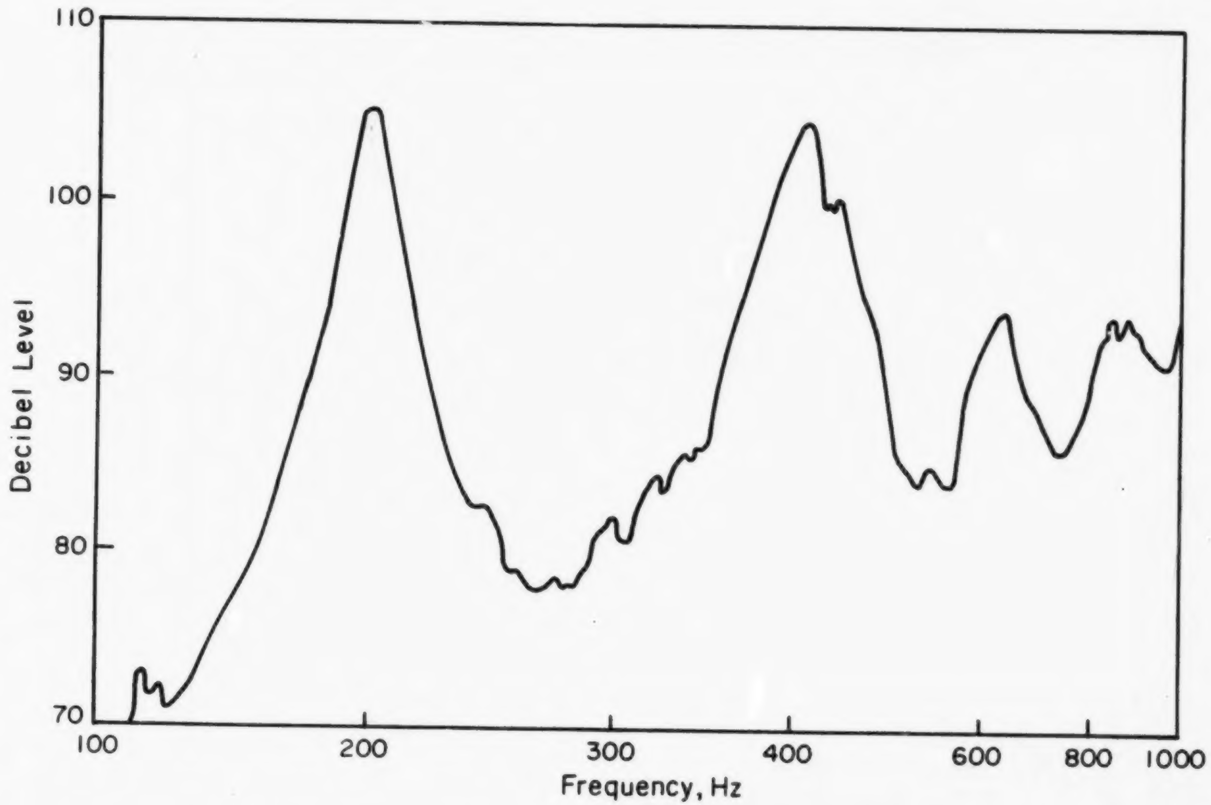

FIGURE C-12. TWO-PULSE COMBUSTORS OF MULLER DESIGN, 4-IN. APART CONNECTED AT COMBUSTION CHAMBERS BY 24-IN. LONG TUBE, AND FIRING AT 200,000 BTU/HR EACH

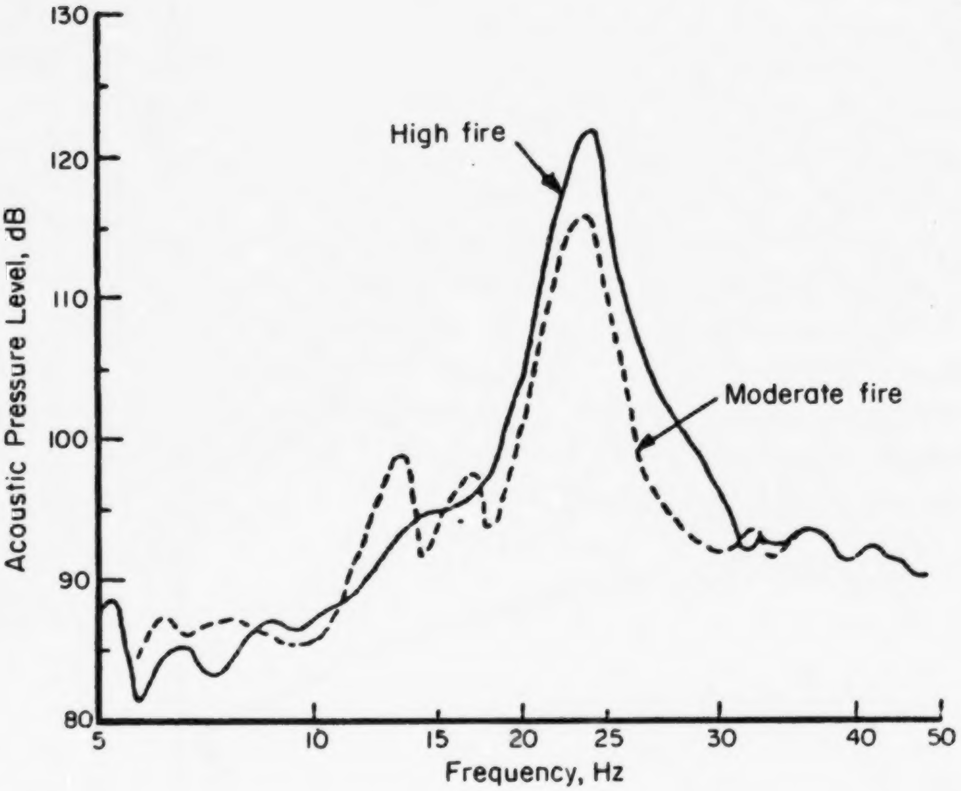

FIGURE C-13. NOISE SPECTRA FOR TWO FIRING RATES OF LARGE AIR HEATER and by governmental agencies in respect to rockets, ramjets, afterburners, and similar combustion systems.

Reference 19 is used as a basic reference for following discussion of combustion-driven oscillations, since it covers the work reported in the literature that is related to residential and industrial combustion systems. A review of this work shows that the probability that a specific change in boiler design (including burners) to reduce pollution will promote combustion-driven oscillations is a function of the driving mechanisms that may be present and the specific details of design. Since more than one type of driving mechanism is possible in most combustion systems, and since many of the acoustic and flow details of a combustion system cannot be computed on the basis of present knowledge, the prediction of the effects of the specific design change would appear to be best handled on a probability basis. In fact, it has been shown for certain combustion systems that, while some design change (for other purposes than pollution control) have a high probability of eliminating combustion-driven oscillations, there is also a finite probability that they can worsen the situation.

However, in respect to some of the changes in design that might be expected to eliminate pollution, some comment can be made relative to the information in Reference 19 without looking at the details of design. For instance, if staged-combustion is to be used, then one would expect that the first stage of combustion will take place with a richer than stoichiometric mixture. Thus, there is a high probability that the burning velocity will be greater than would be the case if staged combustion were not used. An increase in burning velocity generally will tend to produce a higher probability of occurrence of combustion-driven oscillations.* Thus staging can be expected to increase the incidence of this type of problem. The use of low excess air falls in the same category as that of staged combustion.[*]

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* Pulse combustors appear to perform better with fuel-rich mixtures.

On the other hand, when the use of recirculated products of combustion is considered, the recirculated product will have been cooled from the maximum gas temperature. This will result in a reduction of the burning velocity and the basic chemically controlled reaction rate per unit volume (see previous discussion on flash-back gradient). Both of these changes are expected to reduce the probability of occurrence of combustion-driven oscillations. The use of water injection falls into this same category.

The situation relative to biased combustion is not clear cut. Since some of the burners will be operating closer to stoichiometric or possibly even on the fuel-rich side, the general tendency would be for these burners to be a source of driving and to produce an increased probability of combustion-driven oscillations. On the other hand, some of the burners will be operating farther from stoichiometric on the excess air side; these would tend to decrease the probability of generation of combustion-driven oscillations. In addition, there is the possibility that the two basic time lags of the two types of burner loadings could be made such that under no circumstance could driving occur at the lower frequencies of a combustion system.

One factor should not be overlooked. In the history of development of burner-combustion systems one finds many problems of combustion-driven oscillations. In the slow development of these systems in the past, such problems were handled in a routine way, without receiving a great deal of notoriety. However, with pressure for major changes across the board of burner-furnace designs, the problems associated with combustion-driven oscillations, although no more severe on a system basis than in the past, will be more severe on the basis of the availability of time and engineers to solve the problems. This effect is already showing up as new low-pollution installations are made.

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[*] Dykama(43) reported an interesting case in which secondary air was introduced by cutting off the fuel from the lowest bank of burners. The timing of the periodic component of the heat release rate in this case, resulting from a first mode standing wave in the furnace, is such as to supply energy to maintain the oscillation. On the other hand, the timing was incorrect for driving with the secondary air supplied above the burner.

Suppression of Combustion-Driven Oscillations. There are several approaches to the suppression of combustion-driven oscillations. (19,20) If the feedback system is known, suppression of the amplifying effect of any or all the steps in the feedback cycle would help. That is, the ratio of output amplitude to input amplitude in each step should be reduced. For instance, if a flashing flame as a result of a periodicity in velocity is involved, the flame might be stabilized.* An alternative approach is to shift the response time between output and input.

A second approach is to relieve the pressure in the region of maximum pressure amplitude by an orifice or port to the surroundings. However, this is not always a practical solution. An alternative is to return part of a pressure signal out of phase with the acoustic pressure oscillation in the combustion system. This can be done by the use of quarter-wave tubes or Helmholtz resonator.

Damping and sound-absorbing materials may also be used, alone or in combination with other approaches. In the case of frequencies below about 200-400 Hz, this is not usually a practical approach, however. In cases where feedback into the combustible mixture line, the fuel line, or the air line is involved, and sufficient pressure is available, an impedance matching device at the exit of the pertinent line can often be used successfully.

Baffles at the entrance, exit, and in the interior of the combustion system have been used successfully on various occasions, but the reason for the success has not always been clear. Two specific examples are porous duct sections and restrictive orifices at the exit of tunnel burners.

Enclosure Effects. A brief comment should be made about the consequences of various comparative values of the natural frequencies o furnace and enclosure (or room). There will be little tendency of a room to oscillate in response to the furnace frequency if no natural frequency of the room or enclosure is close to the furnace frequency. But if a room frequency and the furnace frequency are close together, and the furnace is near a pressure antinode in the enclosure, the installation will probably produce an intolerably noisy environment.

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* We note that the propensity for this type of driving is directly related to the stability consideration discussion above.

Combustion Roar

General Observations. The basic noise spectrum for combustion roar has no specific frequency but a broad band of noise with a basic form similar to that of noise from a jet. As mentioned above, the peaking frequency appears to be related to the chemically controlled reaction rate per unit volume.(14) Figure C-14 shows a noise spectrum obtained from a natural gas diffusion flame in an anechoic chamber. Typical efficiencies of conversion to roar from chemical energy input of a burner are of the range 10^{-8} to 10^{-6}.(21) It is seen that this is at least two orders of magnitudes lower than the efficiency of conversion expected for combustion-driven oscillations. Little attention was given to this form of combustion-produced noise until recently, when it was realized that it could be a significant contributor to environmental pollution. Currently, however, a considerable amount of attention is being devoted to this aspect of combustion noise and progress is being made rather rapidly in understanding this phenomenon.(14,22) Results have already emerged that are pertinent to boiler design changes to reduce noise levels; any change that lowers the turbulence level of the combustion region or intensity of combustion should result in a lower combustion roar. Therefore, the use of recirculation or water injection would probably tend to reduce the combustion roar output, while the use of staging or biased combustion or low excess air would tend to increase the combustion roar. In general, however, the effects available in one boiler while maintaining satisfactory operation would be far less than the effects which one would expect from changing the basic design to lower the intensity of combustion or the turbulence level.

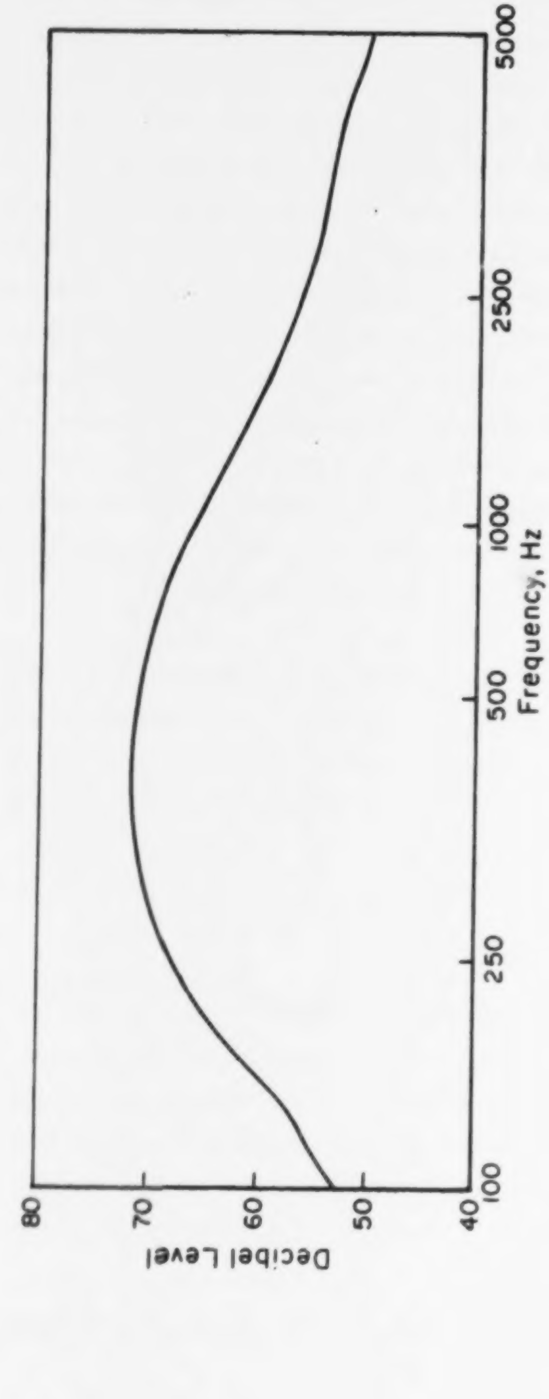

FIGURE C-14. COMBUSTION-ROAR AMPLITUDE-FREQUENCY SPECTRUM AT 40,000 BTU/HR, USING TWO IMPINGING NATURAL GAS JETS

The basic source of noise in the case of combustion roar is well understood. The source is the movement of the flame front in the turbulent flame, as the volume of gas increases on passing through flame front. However, the specific details which would allow a prediction of the noise output from a turbulent flame are not understood. This situation is understandable since the specific details of the propagation of a turbulent flame are not completely understood as yet and the production of noise adds one more level of complication to the problem. However, it is valuable to consider this noise production in a simplified way, to determine how various outside factors may affect the amplitude of noise produced by a combustion system. The following comments are based on a consideration of the literature on combustion noise and the various mathematical models of combustion roar presented therein. The comments presented are not in agreement with many of those commonly cited in the literature. However, it is believed that the presentation presented herein is both technically and intuitively acceptable. and does form a basis for organizing available information.

Theory of Combustion Roar. The basis for the following discussion is the assumption that, from an acoustic point of view, a turbulent flame of commercially significant size is composed of an array of monopole sources.*(23,24) The sound power, G, produced by N monopole sources is given by

$$G = \left(\frac{\rho N}{4\pi c}\right) \left[\frac{d}{dt} (E - 1)q\right]^2 , \qquad (5\ )$$

where E is the volume expansion ratio of the burned to the unburned gas, and q is the volume rate of consumption of the combustible gas in each element. We assume that the time of consumption of an element is proportional to d_f/u', where d_f is the element thickness and u' is the intensity of turbulence. Thus we can replace d/dt by u'/d_f. We also assume that $qN = Q$, where Q is the volume firing rate of the flame. Making these substitutions

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* A monopole source can be pictured as a sphere, periodically expanding and contracting radially.

$$G = \left(\frac{\rho c q Q}{4\pi c}\right)\left(\frac{E - 1}{d_f}\right)^2\left(\frac{u'}{c}\right)^2. \qquad (6)$$

With some further manipulation and the assumption that the burning velocity, F, equals $q/d_f^{\,2}$, the efficiency of conversion of chemical energy to acoustic energy, η, is given by

$$\eta = \left(\frac{\gamma - 1}{4\pi}\right)(E - 1)\left(\frac{F}{c}\right)\left(\frac{u'}{c}\right)^2 . \qquad (7)$$

We note that the efficiency is a function of the product of a term depending on the fuel and mixture ratio, and a term depending on the turbulence level in the combustion region.

Further considerations of this model, discussed in Reference 24, justify a proportionality of the peak frequency of the roar spectrum (see Figure C-14) to the chemically limited reaction rate per unit volume of the combustible mixture.

General Conclusion from Combustion Roar Theory. Several conclusions may be drawn from the above theory. These will be applied to thrust controlled flames. For buoyancy-controlled flame, the intensity of turbulence assumption that is made in this discussion would have to be modified. This would result in slightly altered conclusions.

Change in Firing Rate of Single Burner. For a single burner with a fixed fuel and fuel/air ratio, we can assume that $u' \approx U \approx Q$ where U is a typical flow velocity and Q is the heat release rate. If W is the noise power output,* then $W \approx Q^3$ and PWL (decibels) $\approx$ 30 log Q.

Effect of Change in Burner Size. If a homologous series of burners is considered, each firing at its rated capacity and pressure drop, then (neglecting Reynolds number effects) u'/c is a constant. It follows that the efficiency of conversion is a constant. Thus, $W \approx Q$ and $PWL \approx 10 \log Q$.

---

* SPL (dB) = PWL (db) - 20 log R(feet) - 0.5 where SPL is the sound pressure level at a point R feet from the source, assuming spherical expansion of the sound from the source.

It also follows that a change in the number of burners for a given application, if from the same series and all fired at rated capacity, will not change the combustion roar output. Figure C-15 shows a correlation of three sizes of premix burners, singly and in pairs, on this basis.

Effect of Intensity of Combustion. The intensity of combustion, I, is proportional to U/L where L is the modular size associated with a particular combustor. With some manipulation, one can determine that $W \approx Q^{5/3} I^{4/3}$, or $PWL \approx 16.7 \log Q + 13.3 \log I$. Thus, if the intensity of combustion is maintained throughout a series of designs, say, by increasing the number of modules and maintaining the characteristic velocity, the noise output will increase with somewhat less than the square of the combustion energy input. It might be noted some series of burner designs are constructed on this basis. This could explain the results reported by Bitterlich(25) and Seebold(26).

Effect of Flame Size. The effect of flame size is not well understood and may involve more than one phenomena. First of all, there is an overall effect from the change in intensity, if the firing rate is held constant. But second, there is a change in roar spectrum shape; as the flame gets larger a gradual cut-off on the high frequencies moves to longer wavelength or lower frequencies.(22) Because of the response of the human ear, the effect can become quite pronounced for large flames. This could make the use of a single large burner preferable to two smaller burners.

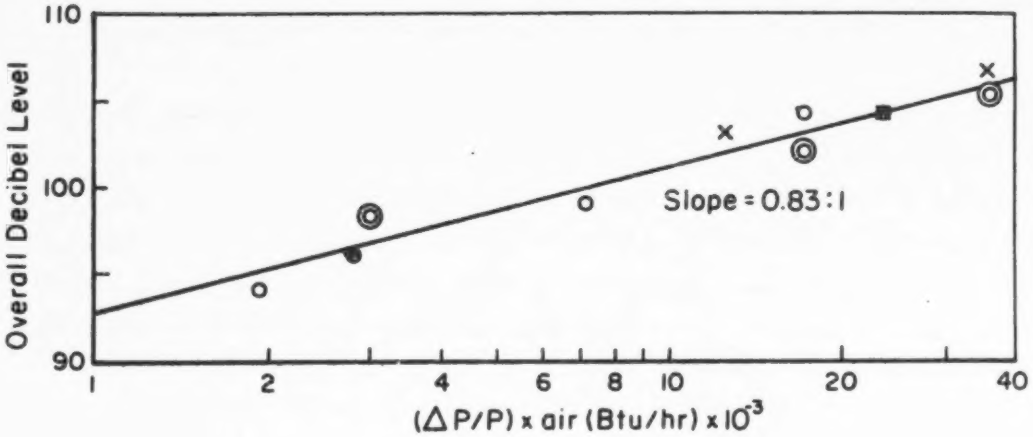

FIGURE C-15. OVERALL DECIBEL LEVEL (SPL REF. 20 MICRONEWTONS/METER^2) AT 3 FEET FROM PREMIX BURNER(S) AS A PRODUCT OF PRESSURE DROP ACROSS BURNER AND BTU/HR BASED ON AVAILABLE AIR. DIFFERENT SYMBOLS INDICATE DIFFERENT BURNER SIZES. BURNERS OPERATING IN PAIRS ARE INDICATED BY TWO SYMBOLS AT SAME POINT.

Effect of Fuel Composition. In a case of a premixed flame or a nozzle mix burner in which all combustion takes place within the burner, the expansion ratio and the burning velocity are known. One therefore expects that if the overall flow rate is held constant, the efficiency of noise output will peak near stoichiometric and fall off on both sides. Since the heat release rate is limited on the fuel-rich side by the amount of air present, and on the excess air side by the amount of fuel present, a further peaking will be found in plotting dB output against air/fuel ratio. Figure C-16 shows the total effect.

For nozzle mix and diffusion flames, as compared to premixed flames, one expects the burning to take place over a wide range of mixture ratios and to involve more local recirculation of hot products, thus decreasing the effective value of E. As a result of this effect and of change in the effective value of burning velocity, the noise output should be reduced and the noise spectrum flattened and shifted to lower frequencies.

Effect of Fuel Type. Most hydrocarbon fuels do not vary greatly in burning velocity at stoichiometric, or in expansion ratio. However, for high percentages of ethylene, hydrogen, and some other fuels with high burning velocity, the efficiency of noise output is seen from Equation (7) to be increased accordingly.

Effect of Recirculated Products or Steam. Since recirculated products have ordinarily lost at least some, and usually much of their thermal energy above ambient, before they are used to dilute the fresh mixture, the burning velocity and the value of the expansion ratio will both be reduced. As a result, from Equation (7), the efficiency of noise output will be reduced.

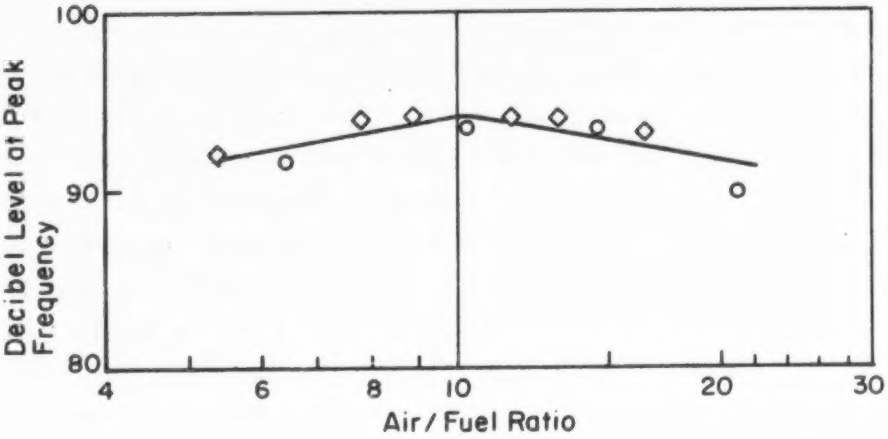

FIGURE C-16. DECIBEL LEVEL AT PEAK FREQUENCY OF A NOZZLE-MIX BURNER, WITH DATA AT CONSTANT NATURAL GAS FLOW RATE (◇), AND CONSTANT AIR FLOW RATE (O), CORRECTED TO CONSTANT TOTAL FLOW RATE

Effect of Environment. While the basic noise spectrum is shaped much like a jet noise spectrum, components of the spectrum are amplified at the natural frequencies of the surrounding environment. For instance, a burner tile around the flame can amplify the combustion roar at the natural axial modes of the tile, as in Figure C-17 . The same holds true for the acoustic modes of the furnace.

Another environmental effect is that of noise from valves or orifices in the fuel or air supply lines. These noises are amplified by the flame, although at the same time the combustion roar spectrum may decrease somewhat.

Application of Combustion Roar Theory. It is not convenient or even possible in most instances to specify the intensity of turbulence in a burner. However, for a series of similar burners one might assume that $(u'/c)^2 \approx (U/c)^2 \approx \Delta P/P$, where ΔP is the pressure drop across the air inlet into the burner (or fuel and air if premixed), and P is the absolute pressure. In case the air is inspirated by fuel jets, the pressure drop across the fuel jets divided by the square of the air to fuel ratio can be used. The data for the efficiency of noise output of a series of similar burners are expected to vary with $(\Delta P/P)^{\alpha}$ where α is close to unity.

Figure C-18 shows data presented on this basis. It is seen that the correlation is quite acceptable for specifying noise output.

Often, the sound power level (SPL) in decibels is preferred. In this case, the SPL can be plotted against $\log (\Delta P/P)^{\alpha} Q$. Within the accuracy of the data, $\log (\Delta P/P)Q$ is often equally acceptable even if not absolutely correct when α is other than unity. Figure C-15 shows data presented on this basis.

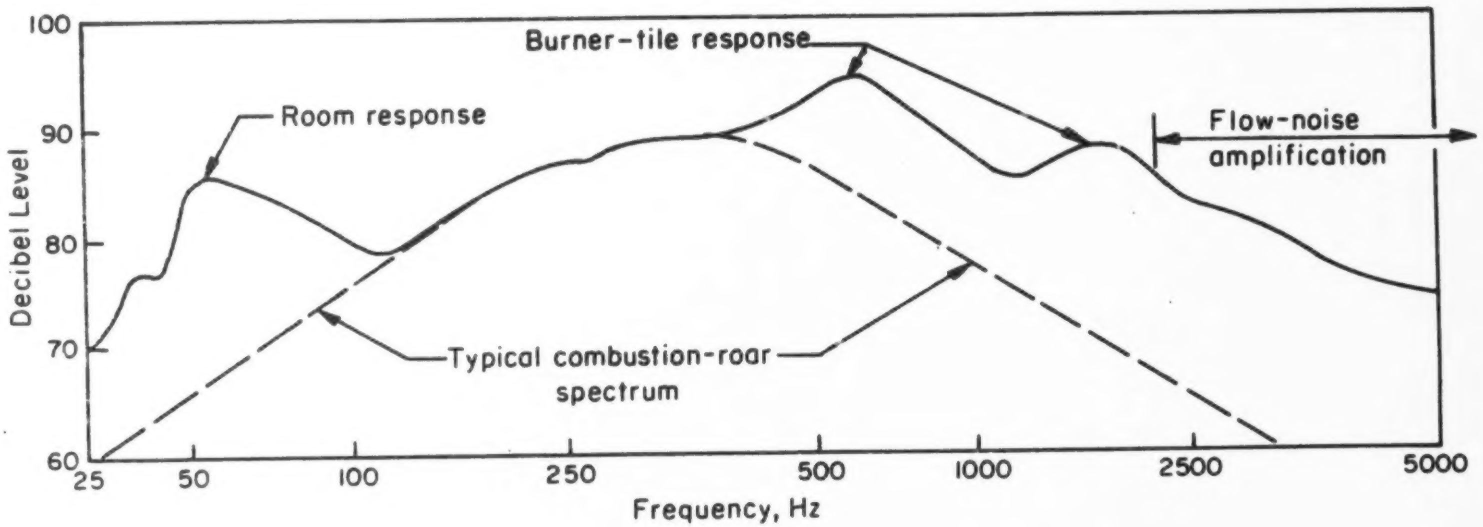

FIGURE C-17. EFFECT OF OTHER NOISE SOURCES ON TYPICAL COMBUSTION-ROAR SPECTRUM FOR A NOZZLE-MIX BURNER

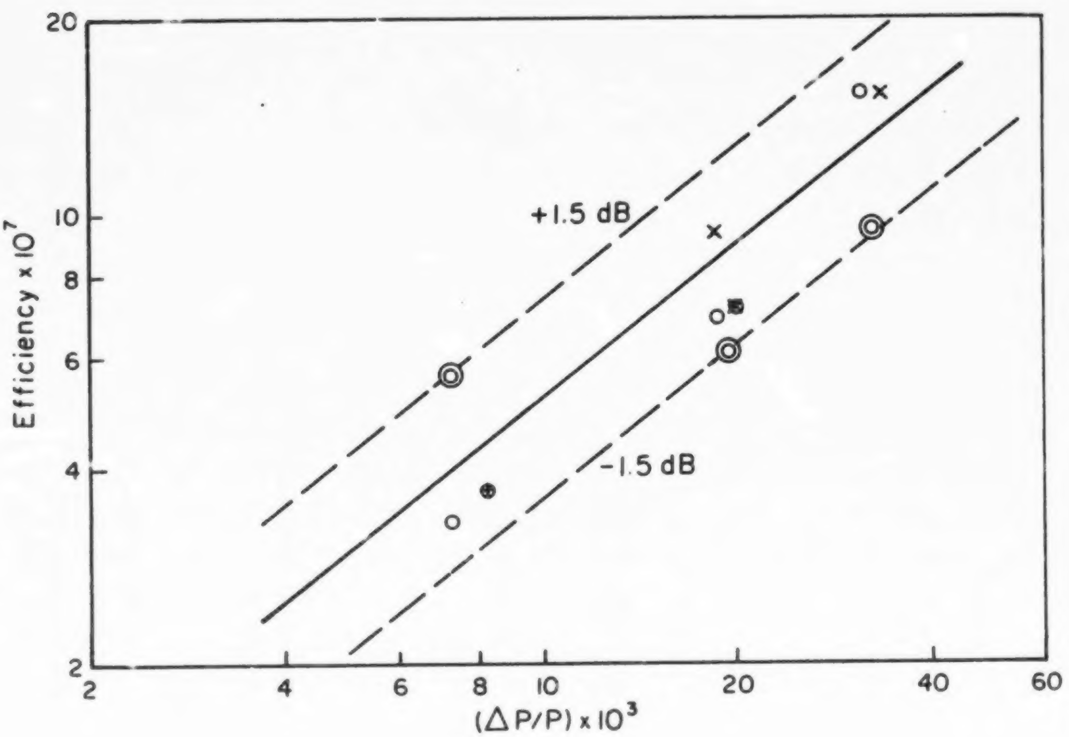

FIGURE C-18. THE RATIO OF EFFICIENCY OF CONVERSION OF CHEMICAL TO ACOUSTIC ENERGY AS A FUNCTION OF DIMENSIONED PRESSURE DROP

Suppression of Combustion Roar. There are several different possibilities for suppressing combustion roar. One of the most obvious, and often very effective, is the installation of mufflers in the inlet and/or exhaust lines, depending on where the prominent noise emanates. Figure C-19 is a sketch of the installation of an inlet muffler on a gas burner for use in banks in oil refineries. Such mufflers quite commonly reduce the dB level by 25. Multiple Helmholtz resonators, quarter-wave tubes, and similar devices can also be used to suppress the combustion roar, especially in cases where there has been amplification of the roar at the natural frequencies of the burner tile or the furnace.

High frequencies imposed on the flame are known to decrease the combustion roar amplitude. Thus Briffa and Fursey(27) have suggested using ultrasonic frequencies to decrease the combustion roar.

Since the combustion roar is known to increase about with the square of the intensity of turbulence, the turbulence level should be reduced as far as possible while still maintaining a satisfactory flame from other points of view.

Unstable Combustion Noise

As noted above there are several types of combustion generated noise that do not fall conveniently into the first two classes discussed. In many instances, these types have not been studied carefully from the noise standpoint or alternatively, it has not been realized that they fall into a separate class. One of these types of combustion-generated noise is that which is related to unstable combustion.

Oftimes flames are unstable and tend to blow off or flash back, as has been discussed previously. However, the flame may not be sufficiently unstable that it is an undesirable flame under normal operating conditions; in fact, visual inspection of the flame may show it satisfactory.

Preferred Design:
Volume: > 15 cu ft
Acoustic material density: 6 lb/cu ft
thickness: > 4 in.
Retainer: expanded metal screen
Heavy plate: ≥ 0.134 in. sound-deadening undercoat

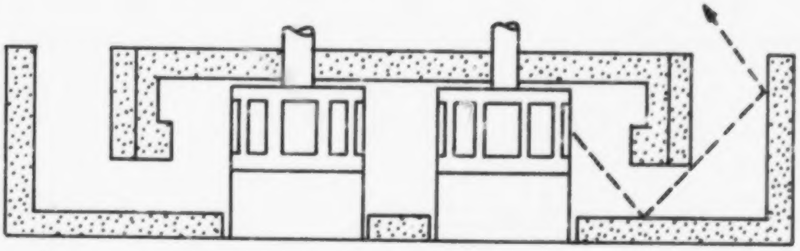

FIGURE C-19. TYPICAL INSTALLATION OF AN INLET MUFFLER ON A GAS BURNER FOR USE IN AN OIL REFINERY

Alternatively, as the flame changes toward, say, blow-off there will be a change in flow pattern and a tendency to reestablish the flame, or a local region thereof, at the expense of some other region. Without a feedback mechanism present in either of these instances, the frequency of such a phenomena is highly erratic. However, the large gross movements of the turbulent flame can produce noise from the moving front of ignition of local combustion cells. Increases of 10 dB or more are not at all unusual when the mixture ratio or flow rate is changed sufficiently to put a flame into a metastable or unstable regime.

Observations of Smith and Kilham. Smith and Kilham(28) reported data on this particular phenomena in 1963. They studied a burner consisting of a long tube with a small pilot flame around the exit. The combustible mixture was 4 percent propane. The flow rate was varied by a factor of about 5 to 1. At each flow rate of the combustible mixture, the supply of hydrogen to the annular hydrogen pilot was varied. As the input to the piloting annulus was decreased the flame suddenly became unstable and the noise level started to increase. With further reduction in the hydrogen flow rate the noise level reached a peak, and then started to decrease as the flame became very tenuous and combustion became incomplete. In these experiments the sound power output increased with about the 5/3 power of the firing rate over a range of 5 to 1. Throughout this range the maximum increase in sound pressure level observed when the hydrogen flow was dropped was about 3 dB. That is, the efficiency of chemical energy conversion to noise increased by a factor of 2 when the flame went into this unstable region, before the flame became too tenuous to be considered as a satisfactorily burning combustion system. It might be noted that this 5/3 power was observed by Giammar and Putnam(22) in small burners when buoyancy effects were important.

Observations of Westberg. Westberg(29) reported the noise output of several industrial burners in industrial and laboratory surroundings. In a set of data on a premixed, continuous-flame, line-type burner, an observed jump in the sound pressure level with increase in firing rate near the rated firing rate can be interpreted as resulting from a flame moving into a partially unstable situation. This jump was about 8 dB. Assuming that this is the correct interpretation of these data, a consideration of the spectrum data before and after the jump shows little change in shape. This would indicate that the overall sound generating phenomena were the same, but the change of the flame into an unstable operating condition resulted in an effective increase in the turbulence level in the combustion region.

Observations of Fricker. Fricker(30,31) discusses the noise produced by a swirl burner with natural gas injected axially at 200 m^3/h. Figure C-20 shows the two types of flames that result. In Type II flame, the central fuel jet is stopped by the recirculation zone and spreads outward to give an intense blue flame. In Type I flame, the gas jet penetrates the recirculation zone with subsequent burning, but leaves enough behind in the reverse flow region to burn and stabilize the flame. Because the Type II flame was noisy and the Type I was quiet, Fricker hypothesized that

(fuel + heat) + combustion air — quiet mixing controlled ignition
(fuel + combustion air) + heat — noisy "explosion" ignition.

Figure C-21 shows the results of a more detailed study of the effect of the ratio of gas velocity to air velocity, and the quarl angle. Two regions are delineated, where Type I and Type II flames exist. When the gas velocity is near the critical value for penetration, the flame is unstable and the noise level is up to 5 dB above that with a stable flame.* Changing the fuel injection from a single axial jet to a multihole divergent set of jets was found to quiet the flame when in this unstable region. For Type II stable flames, the noise level was found to increase linearly from 106 to 114 dB as the swirl number increased from zero to 1.7.

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* Dykama indicates this instability between these two types possibly was the cause of unsatisfactory combustion in one furnace installation, but burner modification solved the problem.(43)

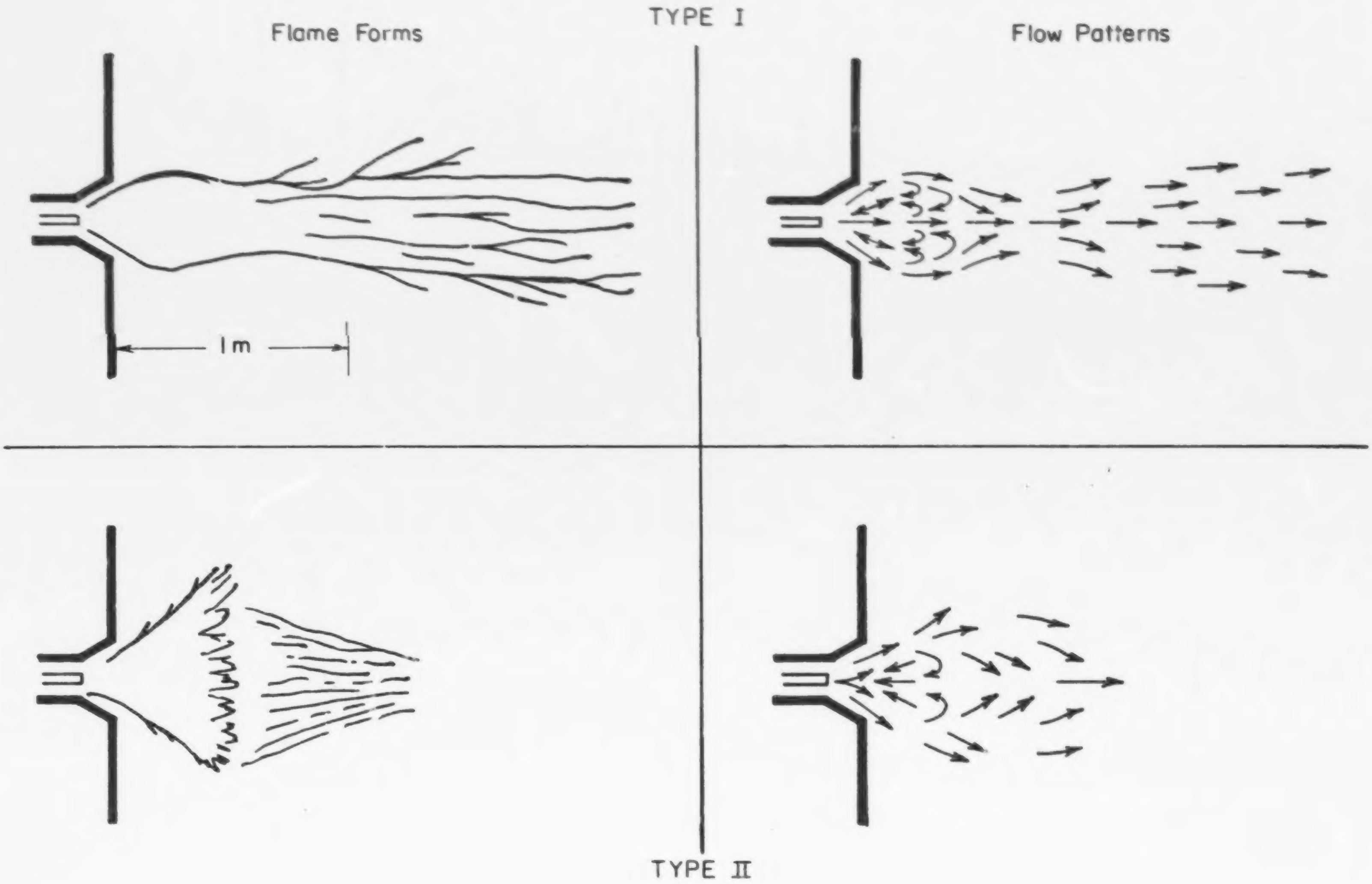
TYPE I
Flame Forms
Flow Patterns
1m
TYPE II

FIGURE C-20. FLOW PATTERNS AND FLAME FORMS OF GAS FLAME WITH SWIRLING AIR FLOW

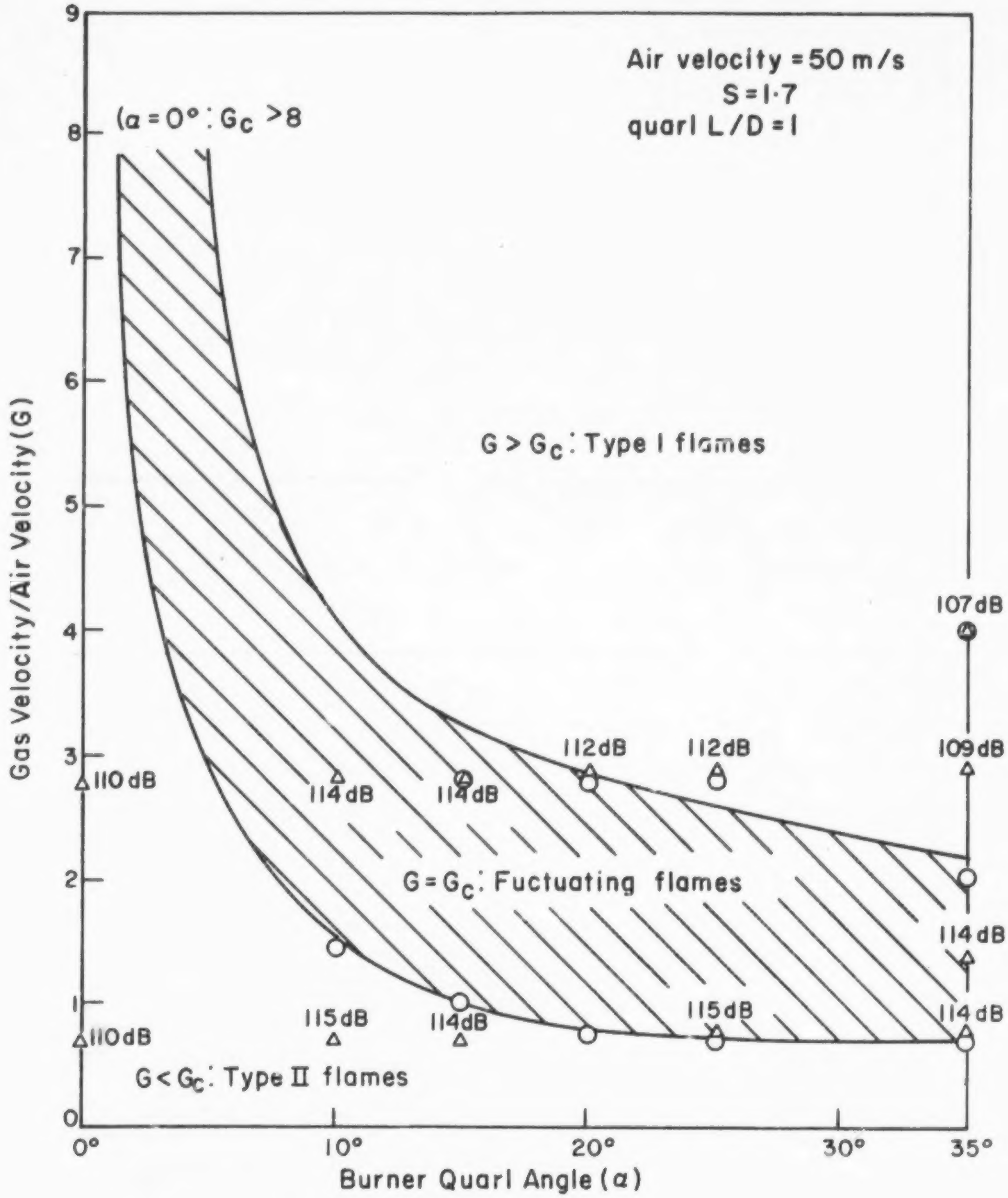

FIGURE C-21. THE DEPENDENCE OF FLAME TYPE AND FLAME NOISE ON BURNER QUARL ANGLE FOR FLAME WITH SWIRLING AIR FLOW AND AXIAL FUEL INJECTION

This latter value corresponds to the swirl of the burner studied by Beer, et al.

Other Observations. Nesbitt(32) indicated that the largest source of combustion noise in industrial combustors is related to the incipient flame instability problem in combustion systems. Unpublished data obtained by the authors on a 4,000,000 Btu/hr nozzle-mix burner indicated about a 10 dB increase in noise level when the unstable region of combustion was entered. It should be noted that from an appearance standpoint, and from a performance standpoint relative to heat output, the burner was still operating satisfactorily.

Data are not yet available to permit a prediction of the increase in decibel level that can be expected when a burner goes into the zone of metastable or unstable operation. The data available indicate anything from a three to a ten decibel increase can be expected. In the case of the observed 3 decibel increase, a larger increase would possibly have occurred if the flame had continued to burn satisfactorily. On the other hand, the little data that are available indicate that the basic phenomena are still one of combustion roar. The change comes about from an increase in the effective level of turbulence at the point of burning. Thus, one would expect that the basic criterion in reducing the noise in cases where the partially unstable burning has to be accepted would be the same criterion of noise reduction one would use for reducing combustion roar.

Combustion Amplification of Periodic Flow Phenomena

There are several variations on the process of noise amplification of periodic flow phenomena by the flame. Because of the lack of understanding of the details of this amplification process, these several different classes have been grouped together. However, the differences will become apparent as various examples are discussed. At present it seems possible to group these examples into the following three subclasses

(a) periodic flow phenomena resulting from an input of a high frequency noise to the combustion system, (b) input of a periodic phenomena by a Strouhal-type vortex shedding in the flow system, upstream of or at the location of the combustion process, and (c) periodic flow phenomena resulting from the swirl flow in swirl type combustors.

External Noise Source. Briffa and Fursey(33) examined the possibility of subjecting a flame to an ultrasonic noise source. He observed that while the ultrasonic noise was amplified by the flame, this amplified noise was outside of the range of hearing. At the same time the combustion roar of the flame decreased in amplitude the order of 2 or 3 dB. It was not clear from the data whether or not the overall noise level produced by the flame was constant or decreased.

Giammar and Putnam(22) observed that the imposition of jet noise in the flow system by insertion of a length of restrictive pipe in the supply line produced a decrease in the amplitude of the combustion roar spectrum of the same order of magnitude as Briffa and Fursey had observed, while at the same time the jet noise itself was amplified by the flame by as much as 25 dB at its characteristic frequency. In this case the jet noise was within the audible range, and this made the burner much more noisy in the audible range. Examination of data on diffusion flames wherein the fuel was supplied by a multiple set of spuds showed the same type of phenomena to be present.(34,35) That is, the jet noise was amplified above what it would have been without combustion, by a factor of up to 25 dB.

It would appear that the superposition of a high frequency note on the turbulent flame results in a change in the burning phenomena sufficient to decrease the low frequency noise spectrum amplitude while amplifying the noise of the superimposed tone.(36)

Strouhal Related Phenomena. In small turbulent flames, it is quite common for a periodic structure to occur in the flame with a frequency spectra having a Strouhal-like characteristic. That is, the peak frequency will have a linear functional relation with the flow velocity. Because the combustion roar may also be present at about the same level of intensity, and in the same frequency range, a clear-cut indication of a vortex shedding (Strouhal-like) phenomena is not always observed.

The best known work in this area is that of Smith and Kilhan.(28) It is commonly assumed that they observed combustion roar, but there are strong indications that they actually observed at the same time a significant contribution of noise amplification of jet noise from the small jets. While the variation of peak frequency with mixture flow velocity that they observed was less rapid than one would expect for a simple cold flow jet, Putnam and Giammar(22) observed this slow variation in peak frequency with small air jets. The frequencies observed by Smith and Kilham give Strouhal numbers of the order of about .2, which is in the region of the expected value. It is also important to note that, while the authors indicated that they observed a noise power output varying with the square of the product of flow velocity, duct diameter, and burning velocity, this conclusion is not correct.

A replot of their data of their Figure 2 in terms of sound power level, which should be independent of microphone position for sufficiently large distances, show that the sound power level for three different diameters of burner, for one mixture ratio, varied with the square of the flow rate, rather than the Reynolds number as they indicated. Their other data were all taken at one constant position for the acoustic probe and one constant burner diameter. Thus the data of their Figure 2 were the only ones that could be used to show up the effect of burner diameter. The interesting fact is that Giammar and Putnam(22) also observed this sound power variation with the fourth power of the diameter for cold jets.

Swirl-Burner Precession Noise. One possible source of noise in a swirl burner is from the precessing of the vortex cores.

Syred and Beér(37,38) present data from both air flow studies and combustion studies on two swirl burners of the design shown in Figure C-22 . Table 2 presents the critical dimensions; it is noted that there is approximately a scale factor of five between the two. For premixed flames, the mixture of fuel and air entered through the swirl vanes. For diffusion flames, fuel was added (1) axially, (2) radially, or (3) tangentially. The first two are obvious. In the third case, the fuel was added through a tube on the axis of the tangential air inlet, terminating at the outer shell wall with the air inlet termination.

Figure C-23 shows the flow pattern obtained from air flow experiments when conditions were such that precession of the vortex occurred. The precessing vortex core appears to lie in the boundary of the reverse flow zone between the zero velocity and zero streamline (cf Figure C-24). At the same time the annular eddy which forms stably at the exit at low flow rates starts shedding and peeling off behind the passing precessing cores. Figure C-25 shows the dimensionless frequency curves obtained in the air flow tests on the two sizes of units.

Since the curves for the two sizes are not identical, it is apparent that the parameter $\Omega D/\rho Q^2$ does not completely characterize the data. Syred (private correspondence) points out two possible reasons. First, he notes that the exact flow pattern of the fluid into the chamber has considerable effect on the value of fd^3/Q. Second, he notes that the correction factor he uses to bring the two curves together is equal to $n^{1/n}$ where n is the scale factor. In any case, it is clear that studies are needed for other values of $\Omega D/\rho Q^2$, as well as other scale sizes, and other designs of entrance.

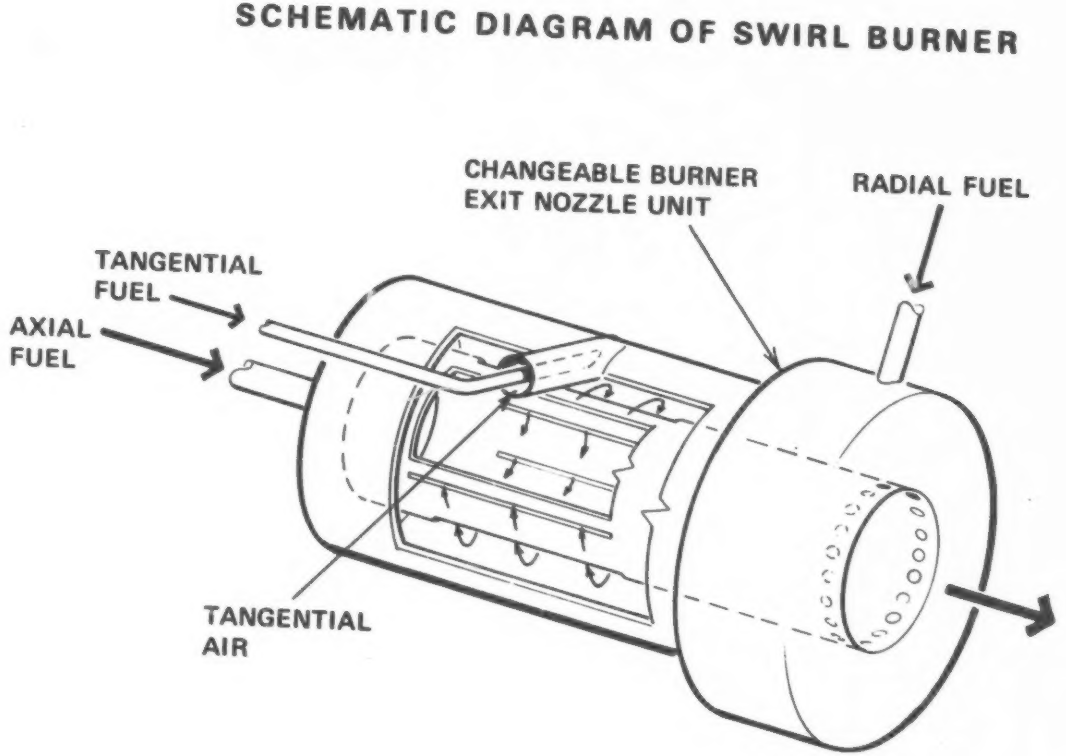
SCHEMATIC DIAGRAM OF SWIRL BURNER
CHANGEABLE BURNER EXIT NOZZLE UNIT
RADIAL FUEL
TANGENTIAL FUEL
AXIAL FUEL
TANGENTIAL AIR

FIGURE C-22. SCHEMATIC DIAGRAM OF SWIRL BURNER

TABLE C-2. SWIRL BURNER DIMENSIONS

	Large	Small
Diameter, mm	176	34
Length, mm	560	100
Number of tangential inlets	8	8
Size of tangential inlets, mm	352 x 4.8	70 x 1.02
Size of axial inlet, mm	12.5	2.0

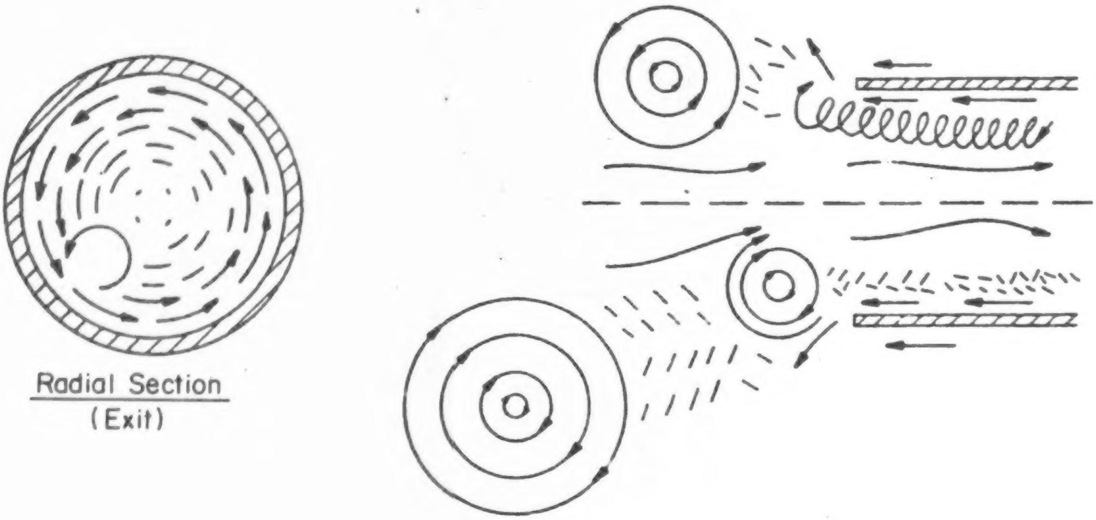

FIGURE C-23. THE ISOTHERMAL FLOW STATE WITH A PRECESSING VORTEX CORE

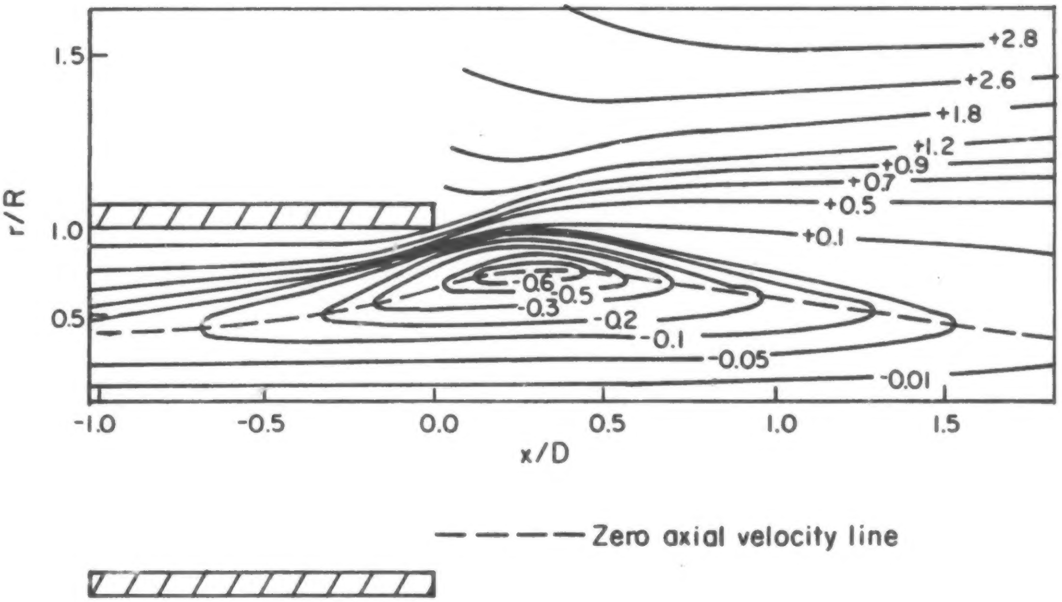

FIGURE C-24. SPATIAL DISTRIBUTION OF STREAM FUNCTION Ψ/Ψ_0

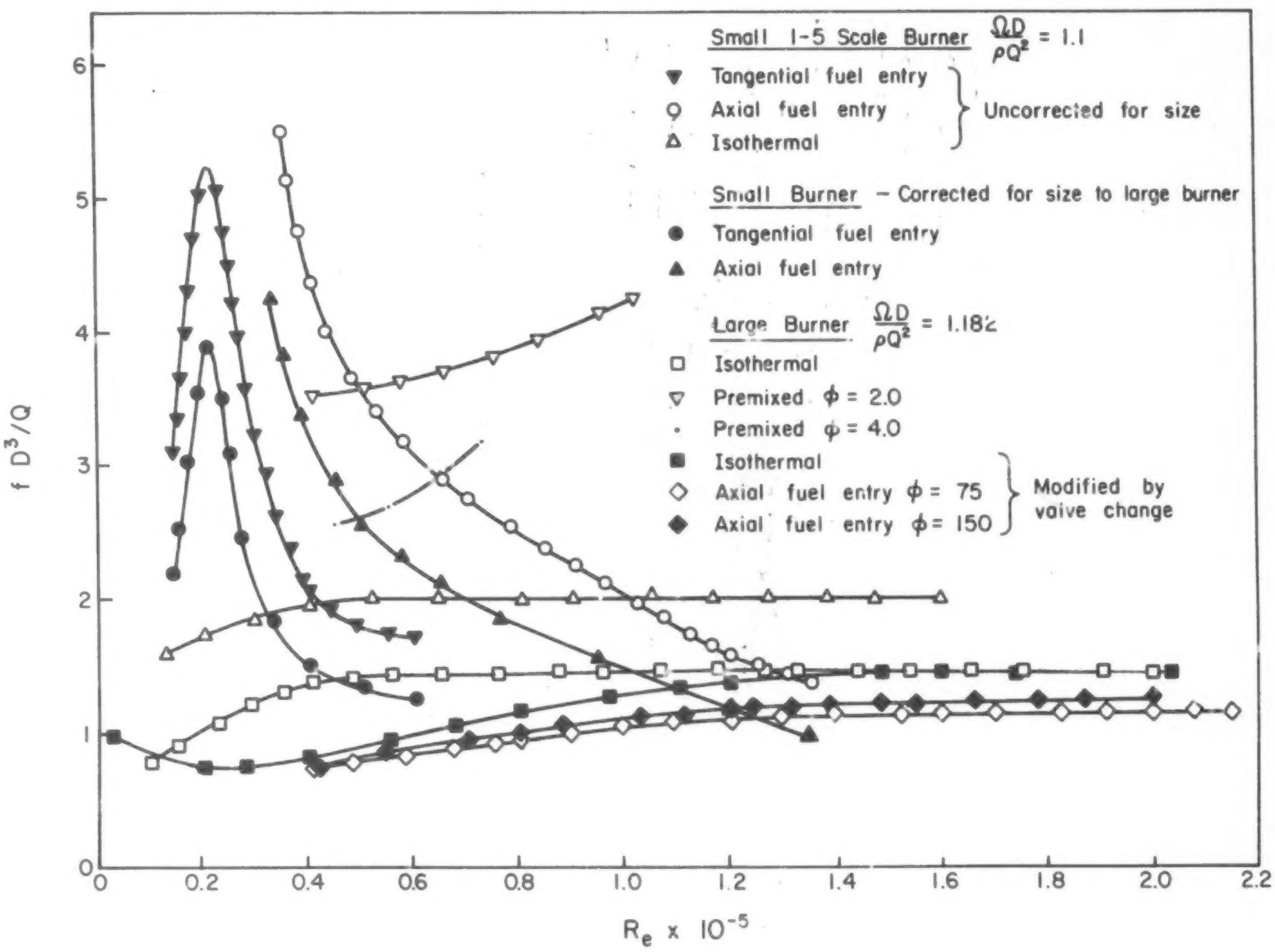

FIGURE C-25. DIMENSIONLESS FREQUENCY AS A FUNCTION OF REYNOLDS NUMBER FOR SWIRL BURNERS, WHERE f = FREQUENCY, D = DIAMETER, Q = VOLUME FLOW RATE, Ω = INLET ANGULAR MOMENTUM. NOTE THAT $\Omega D/\rho Q^2$ is $2/\pi$ TIMES THE CONVENTIONAL SWIRL NUMBER, $2G_\phi/DG_x$

Syred and Beér(39) also studied the noise produced by combustion of premixed natural gas and air in the system, for Reynolds numbers from 4×10^4 up to about 10^5, and air/fuel ratios up to 6 times stoichiometric.* A short, intense, noisy flame was produced. As shown by Figure C-26, the frequency increased by a factor of 2 to 3; the exact value depends on the mixture ratio, with the value increasing as the mixture ratio approaches stoichiometric. The noise intensity was up to 20 times the level without combustion. With town gas (50% H_2) at Reynolds number of 1.4×10^5, the frequency was approximately doubled but the noise amplitude appeared to decrease somewhat.(37)

In studies of natural gas diffusion flames with tangential fuel injection and with axial fuel injection for stoichiometric to about 200% excess air, a 1/5 scale burner was used. The frequency with combustion was about the same as for isothermal flow, but showed less variation with Reynolds number. In a later study, for an axial fuel injection, the frequency decreased about 30% in changing from an infinite air/fuel ratio to 50:1.(40) At less than 50:1, vortex breakdown occurs, while the amplitude was decreased by about 100; this indicates a damping effect of the diffusion flame as the source of noise. Similar suppression effects were obtained with axial injection of town gas but not tangential; apparently the high molecular diffusion rate of the hydrogen in the town gas made this condition similar to the premix case.(37) In another paper(40) these investigators point out that "premixed fuel and air appear to be the only method by which the precessing vortex core may be excited; any other mode of fuel entry damps the precessing vortex core considerably".

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* Apparently the vortex action also results in partial separation of the premixed fuel and air, so as to produce a mixture within the combustible range even at the high excess air values.

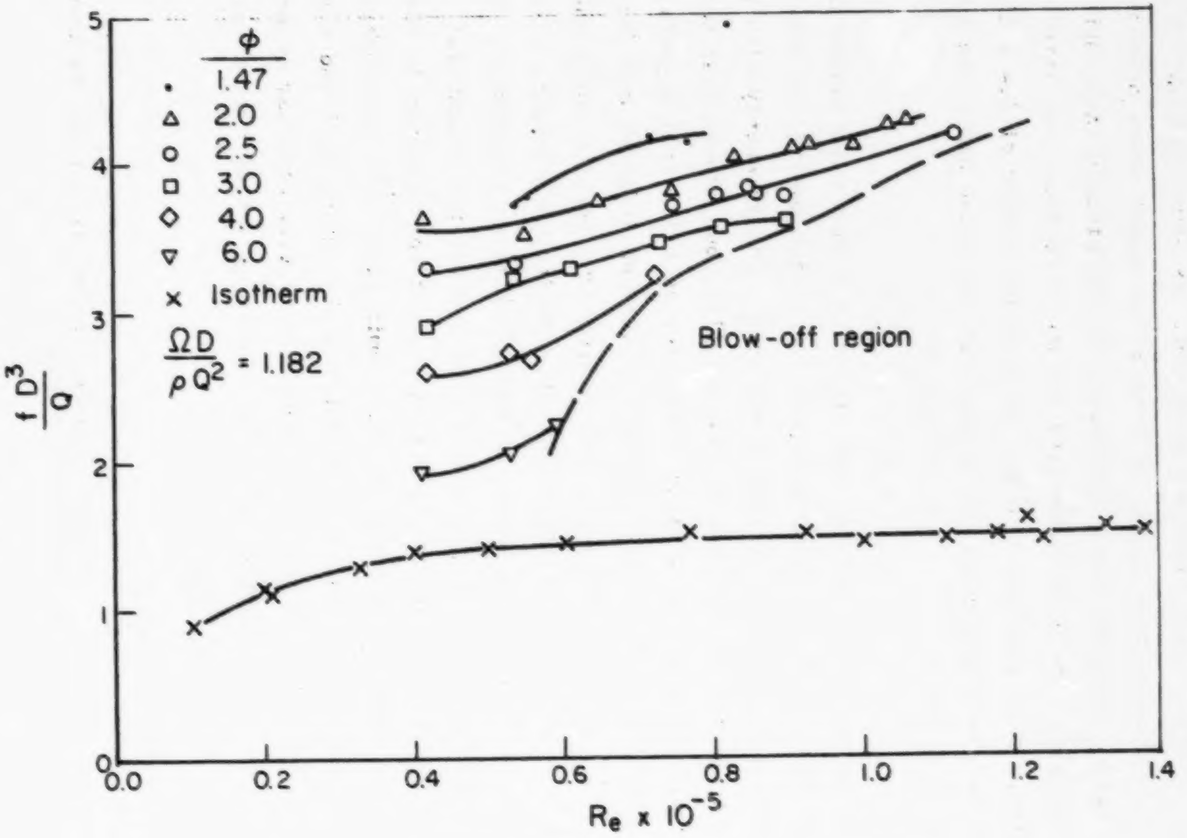

FIGURE C-26. THE EFFECT OF REYNOLDS NUMBER ON THE FREQUENCY PARAMETER FOR PREMIXED COMBUSTION AND ISOTHERMAL STATES

Gupta, Syred, and Beer(43) reported data on the sound pressure level and amplitude-frequency spectra using the smaller natural gas version of the burner shown in Figure C-22.

The sound spectra, such as in Figure C-27, showed no sharp peaks below the approximately 5000 Hz of the jet noise, but a high value in about 200-500 Hz range reported by Giammar and Putnam.(22) The precessing frequency noise observed with isothermal flow was either masked or suppressed by the near-stoichiometric combustion of this diffusion flame as contrasted to the suppression observed with weaker mixtures.

The sound pressure level measurements as a function of excess air from stoichiometric to 20 percent excess air showed little effect up to 1/4 fuel injected radially, and then decreasing amplitude with increased excess air up to about 85 percent radial injection, where stability difficulties entered. For stoichiometric, the 100 percent axial injection was somewhat less noisy than the 85 percent radial, while for 10 percent excess air, the opposite was true. Most interestingly, at about 55 percent radial injection, a dip in the noise output of 1 to 3 dB occurred.

Figure C-28shows that the use of a convergent-divergent nozzle increases the noise level over the minimum by up to 4 dB. At the higher flow rates, the noise levels off and, according to the investigators, is principally jet noise. It is probable that the combustion region has moved outward to a region of lower turbulence intensity, leading to a lower relative noise level.

The fractional efficiency of noise production, as indicated by the straight diagonals, is of the order of 10^{-8}. This is of the order of efficiencies found for low firing rates. The parabolic curve indicates the change of efficiency with firing rate expected on the basis of simple theory, which assumes that the turbulence level in the combustion region is a constant fraction of the flow velocity. If the pressure drop across

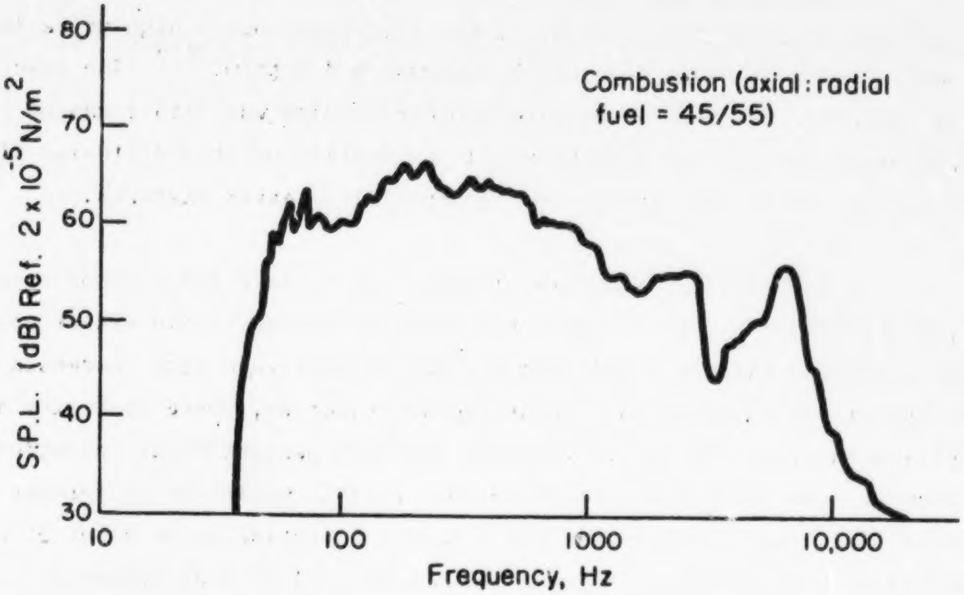

FIGURE C-27. AMPLITUDE-FREQUENCY SPECTRUM FOR MAXIMUM NOISE OUTPUT AT 1.65 x 10^{-3} m^3/s AIR

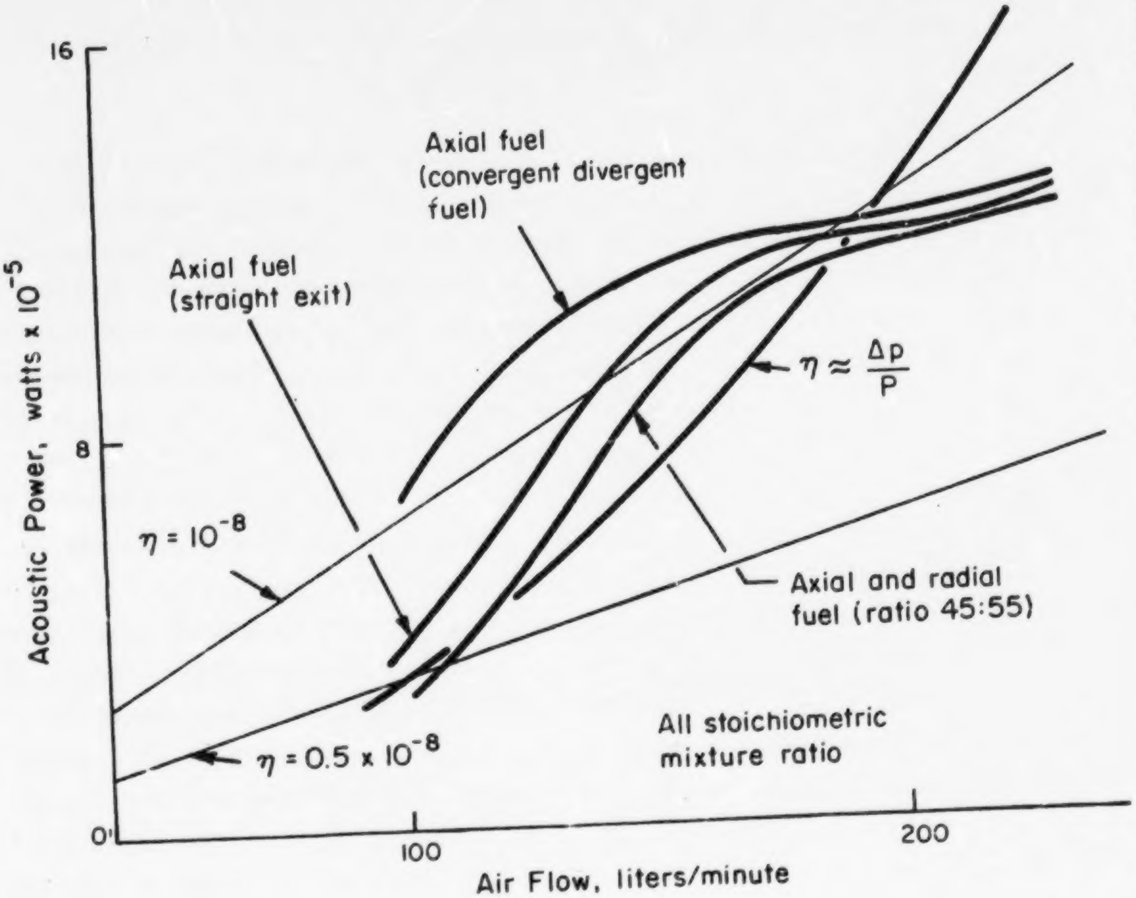

FIGURE C-28. ACOUSTIC POWER OUTPUT OF A SWIRL BURNER AS A FUNCTION OF FLOW RATE the burner is assumed to scale from the larger swirl burner discussed above, this parabolic is about 1/4 the mean value obtained by Giammar and Putnam(24) for premix natural gas flame retention burners (data extrapolated to lower firing rates). A similar comparison based on data from two impinging fuel jets at an optimum spacing for mixing shows good agreement.

Syred, Hanby, and Gupta(41) added a resonance tube of 40 mm diameter to the larger natural gas swirl burner. The fuel was injected either axially or tangentially. Because of the blockage, the resonance tube acted as a quarter-wave tube. It was found that there was amplification of the precessing frequency when the resonant frequency and precessing frequency coincided. However, there were several complicating factors in the study. The precessing frequency, for the axial fuel entry, varied from 140 Hz at the mixture ratio relative to stoichiometric of 1.0, to peaks of 200 Hz at 1.6 and 2.6, and a valley of 170 Hz at 1.8. For tangential fuel entry, the frequency varies from 120 Hz at 1.0 to 160 Hz at 2.3, with fluctuations up to ± 20 Hz, with peaks at 1.0, 1.6, and 2.0. The resonant frequency of the system falls off with increasing tube length, but not at a uniform rate, and is affected by both mixture ratio and mode of fuel injection. Finally, the "Q" of the system is affected by mixture ratio and mode of fuel injection. As a result, there is a major amplified peak at a resonance tube length of 1000 mm and a minor peak at 1400 mm for axial injection, and peaks at 900, 1300, and 1600 (one case) mm for tangential fuel injection, with the major peak at 1300 and 1600 mm. The intensity at a specific measuring point within the combustion system reached twice the amplitude in the case of axial fuel entry as in the case of the tangential fuel entry, but data were not sufficient to obtain a value of efficiency of noise production. It should also be noted that, because of poor blow-off limits of flames with tangential fuel entry, the axial system is preferred.

There does not seem to be any feedback in the system, whereby the resonance amplitude tends to shift the precessing frequency or sharpen it. Rather, the amplification phenomenon appears similar to that discussed by Giammar and Putnam(22) for combustion roar from a burner in a tile.

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